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January 31, 2004
BVY 04-008

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Vermont Yankee Nuclear Power Station
License No. DPR-28 (Docket No. 50-271)
Technical Specification Proposed Change No. 263, Supplement No. 5
Extended Power Uprate – Response to Request for Additional Information

By letter dated September 10, 2003, as supplemented by letters dated October 1, 2003 and two letters dated October 28, 2003, Vermont Yankee[1] (VY) proposed to amend Facility Operating License, DPR-28, for the Vermont Yankee Nuclear Power Station (VYNPS) to increase the maximum authorized power level from 1593 megawatts thermal (MWt) to 1912 MWt. The NRC staff has conducted preliminary reviews of the information VY provided in this regard and has requested additional information (RAI) to clarify the submittals[2]. Each of the identified issues has been the subject of discussions held during conference calls between the staffs of the NRC and VY to further clarify the information needs of the NRC staff.

Attachment 1 to this letter is VY's response to each of the draft RAIs received from the NRC staff on December 18, 2003. Because certain RAI responses are deemed to contain proprietary information as defined by 10CFR2.790, Attachment 1 has been designated in its entirety as proprietary information. The specific proprietary information is designated by underline within double brackets. Attachment 2 to this letter is a non-proprietary version of Attachment 1 with the proprietary information removed. It should also be noted that in several cases, the RAI response makes reference to "Exhibits," which are included in Attachment 3 to this letter.

Affidavits that constitute a request for withholding of the proprietary information in Attachment 1 from public disclosure in accordance with NRC regulations are provided by the owners of the proprietary information as Attachment 4 (General Electric Company (GE)) and Attachment 5 (Stone & Webster). The enclosed proprietary information has been handled and classified as proprietary, is customarily held in confidence, and has been withheld from public disclosure. Except for the proprietary information contained in the response to RAI No. IEPB-B-5, the proprietary information in the responses to the RAIs was provided to VY in a GE transmittal that is referenced by the affidavit. The proprietary information has been faithfully reproduced in the enclosed RAI response such that the affidavit remains applicable. The proprietary information contained in the response to RAI No. IEPB-B-5 was provided to VY by

[1] Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. are the licensees of the Vermont Yankee Nuclear Power Station.

[2] A draft NRC request for information (RAI) was transmitted on December 18, 2003, to VY as documented in NRC memorandum from Richard B. Ennis to Darrell J. Roberts under TAC No. MC0761.

A001

Stone & Webster. Stone & Webster's affidavit specifically references the response to the specific RAI. GE and Stone & Webster request that the enclosed proprietary information be withheld from public disclosure in accordance with the provisions of 10CFR2.790 and 9.17.

This supplement to the license amendment request does not change the scope or conclusions in the original application, nor does it change VY's determination of no significant hazards consideration. If you have any questions, please contact Mr. James DeVincentis at (802) 258-4236.

Sincerely,

Jay K. Thayer
Site Vice President

STATE OF VERMONT)
)ss
WINDHAM COUNTY)

Then personally appeared before me, Jay K. Thayer, who, being duly sworn, did state that he is Site Vice President of the Vermont Yankee Nuclear Power Station, that he is duly authorized to execute and file the foregoing document, and that the statements therein are true to the best of his knowledge and belief.

SALLY A. SANDSTRUM NOTARY WINDHAM COUNTY

Sally A. Sandstrum, Notary Public
My Commission Expires February 10, 2007

Attachments (5)

cc: USNRC Region 1 Administrator (w/o attachments)
USNRC Resident Inspector – VYNPS (w/o attachments)
USNRC Project Manager – VYNPS (w/attachments)
Vermont Department of Public Service (w/non-proprietary attachments)

Docket No. 50-271
BVY 04-008

Attachment 2

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263

Extended Power Uprate – Supplement No. 5

Responses to Request for Additional Information

NON-PROPRIETARY VERSION

Table 1-1
Glossary of Terms

Term	Definition
AC	Alternating current
ADS	Automatic Depressurization System
ADHR	Alternate Decay Heat Removal
AL	Analytical Limit
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	Anticipated operational occurrences (moderate frequency transient events)
APRM	Average Power Range Monitor
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
AV	Allowable Value
BHP	Brake horse power
BIIT	Boron injection initiation temperature
BOP	Balance-of-plant
BWR	Boiling Water Reactor
BWROG	BWR Owners Group
BWRVIP	BWR Vessel and Internals Project
CDF	Core damage frequency
CFD	Condensate filter demineralizer
CFR	Code of Federal Regulations
CLTP	Current Licensed Thermal Power
CLTR	Constant Pressure Power Uprate Licensing Topical Report
CO	Condensation oscillation
CPPU	Constant Pressure Power Uprate
CRD	Control Rod Drive
CRDA	Control Rod Drop Accident
CREVS	Control Room Emergency Ventilation System
CRHZ	Control Room Habitability Zone
CSC	Containment Spray Cooling
CS	Core Spray
CUF	Cumulative usage factors

Term	Definition
DBA	Design basis accident
DC	Direct current
DLO	Dual (recirculation) loop operation
ECCS	Emergency Core Cooling System
EFPY	Effective full power years
EOC	End of cycle
EOP	Emergency Operating Procedure(s)
EQ	Environmental qualification
FAC	Flow Accelerated Corrosion
FFWTR	Final Feedwater Temperature Reduction
FHA	Fuel Handling Accident
FIV	Flow induced vibration
FLIM	Failure likelihood index methodology
FPCC	Fuel Pool Cooling and Cleanup
FW	Feedwater
FWHOOS	Feedwater heater out of service
GE	General Electric Company
HX	Heat exchanger
HELB	High Energy Line Break
HCR	Human cognitive reliability
HEP	Human error probability
Hg_a	Inches of mercury absolute
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilating and Air Conditioning
IASCC	Irradiation-assisted stress corrosion cracking
ICS	Integrated computer system
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular stress corrosion cracking
ILBA	Instrument Line Break Accident
IRM	Intermediate Range Monitor
ISP	Integrated surveillance program
LCS	Leakage Control System
LDS	Leak Detection System

Term	Definition
LERF	Large early release frequency
LHGR	Linear Heat Generation Rate
LOCA	Loss-Of-Coolant Accident
LOFW	Loss of feedwater
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
LPSP	Low Power Setpoint
MAAP	Modular accident analysis program
MAPLHGR	Maximum Average Planar Linear Heat Generation Rate
MBTU	Millions of BTUs
MCPR	Minimum Critical Power Ratio
MELB	Moderate Energy Line Break
MELLLA	Maximum Extended Load Line Limit Analysis
MeV	Million Electron Volts
Mlb	Millions of pounds
MS	Main steam
MSIV	Main Steam Isolation Valve
MSL	Main steam line
MSLBA	Main Steam Line Break Accident
MSRV	Main steam relief valve
MSVV	Main steam valve vault
Mvar	Megavar
MWe	Megawatts-electric
MWt	Megawatt-thermal
MSL	Main steam line
MVA	Million Volt Amps
MWe	Megawatt-electric
NA	Not Applicable
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission
NSSS	Nuclear steam supply system
NUREG	Nuclear Regulations
OLTP	Original Licensed Thermal Power

Term	Definition
OOS	Out-of-service
ΔP	Differential pressure - psi
P_{25}	25% of CPPU Rated Thermal Power
PCS	Pressure Control System
PCT	Peak cladding temperature
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Analysis
PSF	Performance-shaping factor
psi	Pounds per square inch
psia	Pounds per square inch - absolute
psid	Pounds per square inch - differential
psig	Pounds per square inch - gauge
RBCCW	Reactor Building Closed Cooling Water
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RCW	Raw Cooling Water
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RIPD	Reactor internal pressure difference(s)
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
RSLB	Recirculation system line break
RRS	Reactor Recirculation System
RTP	Rated Thermal Power
RT_{NDT}	Reference temperature of nil-ductility transition
RWCU	Reactor Water Cleanup
RWM	Rod Worth Minimizer
S_{alt}	CPPU alternating stress intensity
S_m	Code allowable stress limit
SAR	Safety Analysis Report
SBO	Station blackout
SDC	Shutdown Cooling

Term	Definition
SER	Safety Evaluation Report
SGTS	Standby Gas Treatment System
SJAE	Steam Jet Air Ejectors
SLCS	Standby Liquid Control System
SLMCPR	Safety Limit Minimum Critical Power Ratio
SLO	Single-loop operation
SRM	Source Range Monitor
SRV	Safety relief valve(s)
SRVDL	Safety relief valve discharge line
SSP	Supplemental surveillance capsule program
TAF	Top of active fuel
T-G	Turbine-generator
TSV	Turbine Stop Valve
T_w	Time available
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate heat sink
VYNPS	Vermont Yankee Nuclear Power Station

EEIB-A 1

Based on Section 5.1 of the staff's Safety Evaluation of General Electric Nuclear Energy (GENE) Licensing Topical Report (LTR) NEDC-33004P, "Constant Pressure Power Uprate," (CPPU) dated March 31, 2003, the staff requested that the plant-specific submittal address all CPPU-related changes to instrumentation and controls, such as scaling changes, changes to upgrade obsolescent instruments, and changes to the control philosophy. The licensee has not provided this information.

Response:

CPPU-related changes to instrumentation and controls are listed in the table below. No obsolescent instrument changes are required as a result of CPPU. There are no changes to instrument control philosophy as a result of CPPU with the exception of the Recirc Runback logic noted in the table below.

Parameter	Change
Main Steam Line (MSL) High Flow	Respan Transmitters to encompass new 140% steam flow values
MSL High Flow	Replace the 4 of the transmitters used to provide 40% setpoint with more accurate transmitters. Setpoint remains at 40% of CLTP
MSL High Flow	Setpoint changes for new setpoints for 140% isolation at new steam flows
MSL High Flow	Install new indicators on the master trip units
Neutron Monitoring	APRM flow biased scram ALs and rod block limits require changes for CPPU.
Neutron Monitoring	APRMs require re-calibration reflecting CPPU rated power operation.
Neutron Monitoring	RBM's require re-calibration reflecting CPPU rated power operation.
MSL Radiation Monitor	Normal setpoint changes based on new 100% MSL Rad levels.
Feed Water Control (FWC) System, Feed Flow	Respan transmitters for CPPU flows
FWC System, Feed Flow	New indicator/recorder ranges for CPPU flows
FWC System, Steam Flow	Respan transmitters for CPPU flows
FWC System, Steam Flow	New indicator/recorder ranges for CPPU flows
Rod Worth Minimizer	Setpoint change to maintain the setpoint at the same absolute value of steam flow due to the range changes of the associated instruments.
Recirculation pump NPSH trip	Setpoint change to maintain the setpoint at the same absolute value of steam flow due to the range changes of the associated instruments.

Turbine First Stage Pressure	Setpoint change for the scram bypass.
Turbine Control System	Operating setpoint change to address increased steam line DP.
Condensate Flow	Respan transmitters for CPPU flows
Condensate Flow	Computer point respan
Condensate Heater Pressure low	Setpoint change
Condensate Flow to O2 Inj Sys.	Instrument Recalibration
Steam line leak alarm module	Recalibration of transmitter and alarm module
Condensate Pump discharge pressure	Indicator rebanding for new normal press
Feedwater Pump Suction Pressure	Instrument Recalibration
Feed pump Low Suction pressure trip	Setpoint change for low pressure pump trip.
Feed pump Low Suction pressure	Add a second pressure switch to each pump to provide signal for recirc runback on loss of condensate pump.
Recirc MG Control	New runback to reduce reactor power on loss of feed or condensate pump

EEIB-B 1

Provide the results of the additional analysis referenced in Section 10.3.1 of Attachment 6 of your submittal dated September 10, 2003, for the effect of the EPU on the environmental qualification of electrical equipment in harsh environments located inside and outside the containment.

Response:

This confirmatory analysis is in progress. Vermont Yankee Nuclear Power Station (VYNPS) expects to provide the evaluation by April 30, 2004.

EEIB-B 2--Provide in detail information regarding the extensive modifications to the main generator rewind/upgrade, generator hydrogen coolers, and isolation phase bus duct coolers.

Response:

The main generator is being upgraded/rewound from a rating of 626 MVA to a rating of 684 MVA by replacement of the water cooled stator bars. The existing stator bars are original and have experienced some corrosion, leakage and in some instances, deterioration of insulation. The new stator bars have improved design of the water connection to the stator bars with new material and techniques to minimize the chance for leakage. No physical changes to the stator liquid cooling system, generator voltage regulator or excitation system are required.

The generator rotor is being re-insulated to address aging of the existing insulation system and to ensure vibration will remain within acceptable tolerances for CPPU conditions. The rotor rating is not being increased.

The existing generator hydrogen coolers have been determined to have insufficient capacity and are therefore being replaced.

The generator isolated phase bus duct is being upgraded from a rating of 17900 amps to a rating of 19000 amps by replacement of the bus duct cooler and by internal modifications to the bus duct cooling air distribution system. Delta-Unibus, the bus duct manufacturer, is providing the internal design details, the new cooler unit and the new bus rating. The generator no-load disconnect switch is also being upgraded to a 19000 amp rating by Delta Unibus. Modification to the cooling air flowpath within the disconnect switch have t o be implemented to achieve the increased rating.

EEIB-B 3

Provide the evaluation, referenced in Section 6.1.2 of Attachment 6 of your submittal dated September 10, 2003, of the operation of the Condensate and Reactor Feedwater Pump motors at higher summer temperatures at the power uprated condition.

Response:

This confirmatory analysis is in progress. VYNPS expects to provide the evaluation by April 30, 2004.

EEIB-B 4

Address the compensatory measures that the licensee would take to compensate for the depletion of the nuclear unit mega-volt-amperes reactive (MVAR) capability on a grid-wide basis.

Response:

In New England, an existing generating station proposing to increase output must apply to ISO-NE, the regional transmission system operator. ISO-NE requires that a System Impact Study (SIS) be prepared and approved to assure the change does not negatively impact the grid. The SIS was prepared by GE Power Systems Energy Consulting, Schenectady, NY under contract to ISO-NE. It was reviewed and approved by ISO-NE's NEPOOL Stability Task Force and ISO-NE's NEPOOL Transmission Task Force and received final review and approval by ISO-NE's Reliability Committee. A copy of the SIS has been submitted on the docket. The SIS addresses transmission system voltage, thermal and stability impacts as a result of the change. The SIS requires that Vermont Yankee implement a number of upgrades to address the impact of the upgrade on the transmission system including the additional MVAR capacity to maintain voltage support on a grid wide basis as a result of the Vermont Yankee (VY) uprate. Vermont Yankee will assure adequate MVAR capacity to the transmission system as described below.

During Step 1 of CPPU (approximately 15% power increase) this MVAR support can be supplied by the VY generator. Step 2 of the CPPU will require the addition of a 60 MVAR capacitor bank at the VY 115 kV switchyard.

The existing VY Generator is rated 626 MVA. The nominal gross output of Vermont Yankee is currently about 550 MWe. The existing generator VAR capability at rated output corresponding to a 550 MWe output is approximately 330 MVAR; however, VY experiences increased Turbine Generator vibration at MVAR loading greater than 150 MVAR. The vibration is related to uneven heating of the generator rotor at increased field current. The existing generator capability curve and the existing operating point are attached. [See Attachment 3, Exhibit 1, Figure 1] VY has historically reported its reliable MVAR output as 150 MVAR and has used this value in all transmission system studies.

The rewound VY generator will be rated 684 MVA at 0.969 pf. The revised capability curve is attached. [See Attachment 3, Exhibit 1, Figure 2] During the 2004 refueling outage the existing rotor is being re-insulated. The re-insulation of the rotor should remove the existing 150 MVAR output limit. Under CPPU conditions the nominal generator output is analyzed in the System Impact Study to be as high as 667 MWe. At this output, generator MVAR capability would remain at the pre-uprate capability of 150 MVAR.

During Step 1 of the uprate (15% power increase) the VY generator output is analyzed at 630 MWe. Reactive VAR capability from the generator of about 220 MVAR is sufficient to maintain system voltage requirements. During Step 2 of the uprate, the addition of a 60 MVAR capacitor bank at the VY 115 kV switchyard supplies MVAR capability to maintain system voltage requirements. MVAR output from the VY generator will provide the current output of 150 MVAR and the capacitor banks add an additional 60 MVAR.

EMCB-A 1

Section 3.2.2, "Reactor Vessel Structural Evaluation," of Attachment 6 to your submittal dated September 10, 2003, indicates a fracture mechanics analysis was used in conjunction with inner surface exams and cycle counting to assure potential crack growth is smaller in relation to the ASME XI limits for the feedwater (FW) nozzle blend radius location. The Ultrasonic Testing (UT) inspection of the inner surface of the FW nozzles is based on a BWROG report GE-NE-523-A71-0594, Revision 1, August 1999, that was approved by the NRC in a letter dated March 10, 2000. The fracture mechanics analysis evaluates crack growth for conservative design transients. The conservative design transients used in the fracture mechanics evaluation conservatively bound changes under CPPU conditions.

Identify the design transients used in the fracture mechanics analysis, compare these transients with those assumed under CPPU conditions and explain why CPPU conditions do not impact the fracture mechanics analysis.

Response:

Design Transients

From transient finite element evaluation it was determined that the peak tensile stress in the blend and bore region of the feedwater nozzle occur soon following the step transients associated with initiating feedwater flow and later flow initiation during hot standby. Minimum tensile stress in this region occurs at steady state conditions. Therefore a bounding maximum stress intensity value can be calculated based on a step temperature decrease in combination with pressure stress intensity. The minimum stress intensity can be calculated based on pressure stress alone.

The Vermont Yankee (VY) feedwater nozzle crack growth assessment was evaluated for three design transients. This included Startup/Shutdown cycles, Hot Standby On/Off Flow cycles, and Leak Pattern Changes at power. Maximum stress intensity for each of these transients was calculated based on a step temperature decrease combined with the maximum pressure stress intensity at the time of the transient. The minimum stress intensity was based on pressure stress alone. The conservative values were used for each of the three transients is summarized in Table 1.

Table 1. Transient Conditions used in the ENVY Feedwater Nozzle Crack Growth Assessment				Basis for Temperature Drop	
	Maximum Stress Intensity Value		Minimum Stress intensity Value		
Design Transients	Temperature Drop, delta T	Pressure	Pressure	Start	Finish
	Deg F	Psig	Psig	Deg F	Deg F
Startup/Shutdown	502	1025	0	552	50
Hot Standby	452	1025	925	552	100
Leak Pattern Changes	152	1025	1025	528	376

For the Startup/Shutdown and Hot Standby transients the 552°F start temperature is a conservative initial value that bounds expected temperature conditions with or without recirculation flow. The downcomer temperature with recirculation flow is 528°F under Current Licensed Thermal Power (CLTP) conditions and 526°F under CPPU conditions. Without recirculation flow the coolant saturation temperature would conservatively bound the temperature in the downcomer region. The saturation temperature is 547°F under CLTP and CPPU conditions. Therefore the 552°F remains a conservative initial temperature for analysis.

During normal startup, feedwater temperature is at or above building and drywell ambient temperature; >70°F. During feedwater startup after an outage the feedwater system is run in a closed cycle to the condenser to clean the water. This cycling is effective in preheating the hotwell inventory prior to vessel injection. Power uprate will not impact the injection temperature. Therefore 50F is significantly lower than expected feedwater temperature under CLTP and CPPU conditions.

It should also be noted that during normal startup, the low flow feedwater control valve would keep a constant flow of feedwater from the condenser hotwell and there will not be a step change in temperature at the nozzle. Therefore calculating stress based on a step change is a very conservative assessment.

The most severe Hot Standby cycling occurs during a loss of normal power event (post scram) where both recirculation and feed pumps have been lost. In this condition injection is performed with the HPCI or RCIC steam driven pumps through the feedwater nozzles. The volume of hot feedwater in the feedwater lines provide adequate makeup volume prior to restoration of normal feedwater pump makeup. Due to convective heating at periods of no flow, the injection temperature would be between Reactor Pressure Vessel (RPV) temperature and drywell temperature. Therefore 100°F is significantly lower than expected feedwater injection temperature under CLTP and CPPU conditions.

The normal operating pressure under CLTP and CPPU conditions is 1010 psig. Therefore 1025 psig is used as a conservative value to calculate maximum stress conditions. Using 0 psig as a minimum pressure for all Startup shutdown transients remains bounding under CPPU. For hot standby cycling 1025 to 925 psig was used. This differential bounds observed feed and bleed scenarios during Loss of Normal Power (LNP) and other hot-standby injection events for CLTP and CPPU operation.

The leak pattern change transient depicts a change in the leakage pattern at the thermal sleeve to safe-end seal. At CLTP full power conditions VY maintains 376°F feedwater temperature and a 528°F downcomer temperature. Therefore conservatively the largest temperature excursion expected from leakage pattern changes would be 152°F (528°F – 376°F). There is no pressure change associated with leak pattern change events. Under CPPU conditions GE calculated that VY will maintain a 392°F feedwater temperature and a 526°F downcomer temperature. Therefore the largest temperature excursion expected from leakage pattern changes would be 134°F (526°F – 392°F). Therefore the 152°F value used in the existing fracture mechanics evaluation remains bounding for CPPU.

Temperature Distribution Along the Nozzle Wall:

Another important consideration in the stress analysis in the crack growth assessment is the assumed temperature distribution along the nozzle wall behind the thermal sleeve. This temperature is influenced by conduction through the thermal sleeve and bypass leakage that enters the annulus between the thermal sleeve and nozzle. With CPPU the feedwater flow will increase 25% (120% power) and the bypass flow is expected to also increase 25%. In the VY crack growth assessment bypass leakage was bounded by assuming that the fluid temperature behind the thermal sleeve was at feedwater temperature. Therefore the applied temperatures remain bounding for CPPU conditions.

Heat Transfer Coefficients

Another item that is used in the stress evaluation of the nozzle is the heat transfer film coefficient along the inside of the nozzle. A conservative heat transfer coefficient of 1000 Btu/hr-F-ft^2 was employed in this analysis. This value would be appropriate for bypass leak rates as high as 235 gpm. Conservative estimates of bypass leak rates indicate that leakage under current feedwater flow conditions would be less than 23 gpm. Under CPPU conditions this would increase to 1.25 x 23 = 29 gpm. Therefore the heat transfer coefficient of 1000 Btu/hr-F-ft^2 is bounding under CLTP and CPPU conditions.

<u>Frequency of Transient Events</u>

The VY crack growth assessment is based on a conservative projection of startup/shutdown, hot standby, and leak pattern exchange transients between UT examinations. VY also monitors and tracks these events to identify if a more frequent exam schedule is warranted. While VY does not expect the frequency of these events to increase under CPPU VY will continue to monitor these events under CPPU conditions.

BVY 04-008 Attachment 2 - CPPU Submittal RAI Response
Non-Proprietary Information

EMCB-A 2

Section 10.7, "Plant Life," of Attachment 6 to your submittal dated September 10, 2003, identifies irradiation-assisted stress-corrosion cracking (IASCC) as a degradation mechanism influenced by increases in neutron fluence. This section indicates that the current inspection strategy for reactor internal components is expected to be adequate to manage any potential effects of CPPU. Note 1 in Matrix 1 of Section 2.1 of RS-001, Revision 0 indicates guidance on the neutron irradiation-related threshold for inspection for IASCC in BWRs is in Boiling Water Reactor Vessel and Internals Program (BWRVIP) report BWRVIP-26. The "Final License Renewal SER for BWRVIP-26," dated December 7, 2000, states that the threshold fluence level for IASCC is 5 x 10^{20} n/cm2 (E > 1 MeV). Identify the vessel internal components whose fluence at the end of period of operation with CPPU conditions will exceed the threshold level and become susceptible to cracking due to IASCC. For each vessel internals component that exceeds the IASCC threshold, either provide an analysis that demonstrates failure of the component will not result in the loss of the intended function of the reactor internals or identify the inspection program to be utilized to manage IASCC of the component. Identify the scope, sample size, inspection method, frequency of examination and acceptance criteria for the inspection programs.

Response:

Of the reactor vessel internal components, only the top guide's integrated flux will exceed 5 x 10^{20} n/cm^2.

VY will commence inspection of critical top guide components in the refueling outage following power uprate. Enhanced Visual Testing (EVT)-1 of top guide grid beams will be performed in accordance with SIL 554 following the sample selection and inspection frequency of BWRVIP-47 for the CRD guide tubes. In other words, VY will perform inspection of 10% of the total population of cells within twelve years, with one-half (5%) to be completed within six years. The six-year intervals at Vermont Yankee will be defined to be the same as those for the CRD guide tubes. Selection of the cells will be biased to the highest fluence areas in the top guide. However, Vermont Yankee reserves the right to modify the above inspection program should BWRVIP-26 be revised in the future.

EMCB-B 1

Section 3.5.1 of Attachment 4 of your submittal dated September 10, 2003, provides the results of the structural evaluation of the reactor coolant pressure boundary (RCPB) piping. Provide the basis for the disposition of the first system listed in this section.

Response:

The Reactor Recirculation (RR) piping system is [[
]] is that for the RR system, there is no significant change in temperature, pressure and flow rate for the RR piping system resulting from CPPU. For Vermont Yankee, the RR system is [[
]] since the temperature, pressure, and flow rate changes resulting from CPPU are insignificant. The RR operating temperature will decrease slightly (by less than 1 percent). The RR operating pressure changes by less than 1 percent (RR pump suction pressure decreases by less than one percent and RR pump discharge pressure increases by less than one percent). The RR flow rate which increases slightly (by less than 2 percent) is acceptable since this system does not contain any fast closing valves. In summary, the temperature, pressure and flow rate changes are very minor and do not significantly impact the existing piping system qualification.

EMCB-B 2

Identify the materials of construction for the Reactor Recirculation System piping and discuss the effect of the requested EPU on the material. If other than type "A" (per NUREG 0313) material exist, discuss augmented inspection programs and discuss the adequacy of augmented inspection programs in light of the EPU.

Response:

Vermont Yankee submittal letters to Generic Letter GL 88-01, FVY 88-62 dated 7/27/88 and BVY 89-70 dated 7/25/89, state the entire Reactor Recirculation system is Category A material. Also, it is stated that all piping in the Recirculation System is low carbon Type 316 stainless steel.

The weld residual stresses and not the operating stresses are the major contributing factor in the initiation of cracking in BWR materials subject to IGSCC. Since the weld residual stresses do not change due to introduction of CPPU, it is concluded that CPPU will not have an effect on materials subject to IGSCC.

EMCB-B 3

Section XI of the American Society of Mechanical Engineers (ASME) Code allows flaws to be left in service after a proper evaluation of the flaws is performed in accordance with the ASME, Section XI rules. Indicate whether such flaws exist in the Reactor Recirculation System piping and evaluate the effect of the EPU on the flaws.

Response:

There are no known flaws in the Reactor Recirculation system piping.

EMCB-B 4

Discuss flaw mitigation steps that have been taken for the RCPB piping and discuss changes, if any, that will be made to the mitigation process as a result of the EPU.

Response:

In addition to the IGSCC mitigation measures described in letters FVY 88-62 dated 7/27/88 and BVY 89-70 dated 7/25/89, Vermont Yankee has adopted Hydrogen Water Chemistry with Noble Metal Chemical Addition. Hydrogen injection rates will be adjusted as power is increased to maintain protection.
Refer to PUSAR SECTION 10-7 Attachment 4 for additional details.

EMCB-C 1

In Section 4.2.6 of Attachment 6 to the submittal dated September 10, 2003, the licensee states that the debris loading on the suction strainers and the methodology used to calculate available Emergency Core Cooling System (ECCS) net positive suction head (NPSH) for CPPU are the same as the pre-CPPU conditions. What assumptions are used with respect to failure of protective coatings and organic materials for the post-accident performance of the ECCS (pre-CPPU and post-CPPU)?

Response:

The methodology used by Vermont Yankee to determine the amount of debris generated and transported to the strainers is generally based on NEDO-32686, the BWROG Utility Resolution Guidance for ECCS Suction Strainer Blockage.

The assumption used for protective coatings, specifically inorganic zinc with epoxy top coat, was 0.65 cubic feet or 85 lbm [Section 3.2.2.2.2.1.1, NEDO-32686, Rev. 0]. This is a bounding value and is not affected by CPPU.

Organic materials were assessed as unqualified coatings (i.e., carbon-based paint chips) via testing of the ECCS strainer design under simulated LOCA conditions at Alden Research Labs (ARL). Quantities of paint chips and fiber debris were included in the test program. During the testing, paint chips added to the pool did not contribute to the head loss due to post-LOCA debris for the strainer approach velocities and suppression pool turbulence conditions calculated for Vermont Yankee. Strainer approach velocities are not affected by CPPU. The results of the containment analysis at CPPU conditions were within the conditions used to define the chugging loads [Section 4.1.2.1 of Attachment 6 to the submittal dated September 10, 2003], therefore suppression pool turbulence is not affected.

The above results support the conclusion in Section 4.2.6 of Attachment 6 to the submittal dated September 10, 2003 that the debris loading on the suction strainers and the methodology used to calculate available Emergency Core Cooling System (ECCS) net positive suction head (NPSH) for CPPU are the same as the pre-CPPU conditions.

EMCB-C 2

In Section 10.7 of Attachment 6 to the submittal dated September 10, 2003, the licensee addresses the Flow-Accelerated Corrosion (FAC) program for VYNPS. The program consists of inspecting selected components and subsequently using the inspection results to qualify all the FAC susceptible components for further service. In order to evaluate the licensee's program, the staff requires the following additional information:

a. In the FAC program, what are the criteria for selecting components for inspection after the EPU?
b. What are the changes in the predicted wear rates after the EPU in the Main Steam Drains, Moisture Separator Drains, and the Turbine Cross Around System piping?
c. What are the changes of velocity and temperature of the feedwater caused by the EPU?

Response:

a. The criteria for selecting components for inspection after the CPPU will be the same as used under current licensed power. The criteria are currently located in Section E.2 of Appendix E of Vermont Yankee Program Procedure PP 7028 "Piping Flow Accelerated Corrosion Inspection Program". A copy of Appendix E to PP 7028 is included in Attachment 3, Exhibit 2. For each refueling outage, Inspection Location Worksheets are prepared to document the methods and reasons for component selection. These worksheets are prepared by and reviewed by engineers with FAC related experience and training in the use of the EPRI CHECWORKs Program.

b. Changes in the predicted wear rates after the CPPU in the Main Steam Drains, Moisture Separator Drains, and the Turbine Cross Around System piping are summarized in Table 112(b), attached.

c. Changes in velocity and temperature for the Feedwater piping caused by the CPPU are summarized in Table 112(c), attached.

Table 112(b)
RAI Response to QUESTION 112(b)
Summary of Predicted Wear Changes in Main Steam Drains, Moisture Separator Drains, and Turbine Cross Around Piping
Page 1 of 2

System	Lines	Material	Flow	FAC Susceptibility	Changes in Flow Regime that effect FAC	Expected Changes in FAC Predicted Wear Rates
Main Steam Drains	3" & 8" drain headers to condenser, 6" drip legs off main steam lines	C.S.	Intermittent Flow	Susceptible – Non Modeled	Increased flow	No significant wear observed to date. Expect any wear to increase proportional to flow. Inspections to monitor CPPU effects on piping will continue.
	1" -2" piping at steam traps & level control valves off MS lines to drain headers	C.S.	Intermittent Flow	Susceptible –Small Bore	Increased Flow	No significant wear observed to date. Expect any wear to increase proportional to flow. Inspections to monitor CPPU effects on piping will continue.
	1" & 2" HP turbine lead drains upstream of R.O & V60-12	C.S.	Continuous	Susceptible –Small Bore	Increased Flow	No significant wear observed to date. Expect any wear to increase proportional to flow. Inspections to monitor CPPU effects on piping will continue.
	1" & 2": HP turbine lead drains downstream of R.O & V60-12	S. S. LAS (1-1/4 Chrome)	Continuous	Not Susceptible - Resistant Material	Increased flow	No change expected due to FAC resistant material.
	1", 2", & 2-1/2" lines for valve seat drains	C.S.	Start Up / Normally Closed	Susceptible –Small Bore	Increased Flow at Startup	No significant wear observed to date. Expect no significant change in wear rates due to low usage.
	1" & 2" HPCI & RCIC Steam Supply drain lines to condenser.	LAS (1-1/4 Chrome)	Intermittent Flow	Not Susceptible - Resistant Material	Increased flow	No change expected due to FAC resistant material.

Table 112(b)
RAI Response to QUESTION 112(b)
Summary of Predicted Wear Changes in Main Steam Drains, Moisture Separator Drains, and Turbine Cross Around Piping
Page 2 of 2

System	Lines	Material	Flow	FAC Susceptibility	Changes in Flow Regime that effect FAC	Expected Changes in FAC Predicted Wear Rates
Moisture Separator Drains	6" & 24" piping from Moisture Separator to level control valves	C.S.	Continuous	Susceptible – Modeled in CHECWORKS	Approx.12.5% increase n flow. Approx.20 °F increase in operating temp.	CHECWORKS Pass 2 results shows piping wear rate approx. 3 mills per year with significant times to t min. (LCF=0.128). ~12% increase of low wear rates expected.
	6" & 24" piping downstream of level control valves to No. 2 H.P. feedwater heaters.	LAS (2-1/4 Chrome)	Continuous	Not Susceptible - Resistant Material (included in CHECWORKS model)	Approx.12.5% increase in flow, approx.20 °F increase in operating temp.	Modeled in CHECWORKS. Pass 2 results show no significant wear. No changes in wear rates expected due to FAC resistant material.
	4" & 6" piping downstream of bypass valve to condenser	LAS (2-1/4 Chrome)	Normally Closed	Not Susceptible - Resistant Material	No Change for normal operation.	No changes in wear rates expected due to FAC resistant material.
Turbine Cross Around piping	36"A to D from H.P Turbine to Moisture Separators	GE copper bearing C.S.	Continuous	Susceptible – Non Modeled	Approx. 23% increase in flow. Slight decrease in Moisture content.	Current surface condition of piping is passivated. Internal visual inspections to monitor changes due to CPPU will continue.
	30" A, C, D from Moisture Separators to L.P. Turbines	LAS (2-1/4 Chrome)	Continuous	Not Susceptible - Resistant Material	Approx. 24% increase in flow. Slight decrease in Moisture content.	No change expected due to FAC resistant material. Internal visual Inspections are performed on a reduced frequency.
	30" B from Moisture Separators to L.P. Turbines	C.S.	Continuous	Susceptible – Non Modeled	Approx. 24% increase in flow. Slight decrease in Moisture content.	Current surface condition of piping is passivated. Internal visual inspections to monitor changes due to CPPU will continue.

Table 112(c)

RAI Response to QUESTION 112(c)

Summary of Velocity and Temperature Changes in the Feedwater Piping Caused by CPPU

Feedwater Piping Segment	Lines	Current Licensed Thermal Power [Note 1]		Extended Power Uprate (120%) [Note 2]		Change In Velocity (%)	Change in Temperature (°F)
		Velocity (Ft./ Sec)	Temperature (F)	Velocity (Ft./ Sec)	Temperature (F)		
From FDW Pumps to No. 2 FDW Heaters	16 " Diameter to Header [Note 3]	15.45	296.9	12.77	311.5	-17.3	+14.6
	24" Diameter Header	6.85	296.9	8.49	311.5	23.9	
	10" Diameter at Feedwater Regulator Valves	34.60	296.9	42.91	311.5	24.0	
	18" Diameter to No.2 FWD Heater	12.22	296.9	15.42	311.5	24.0	
From No. 2 to No,.1 FDW Heaters	18" Diameter	12.44	327.7	15.46	344.0	24.3	+16.3
From No. 1 FDW Heaters to Reactor Vessel 1	18" Diameter	12.82	373.1	15.97	391.5	24.6	+18.4
	16" Diameter	16.21	373.1	20.18	391.5	24.5	
	10" Diameter	18.16	373.1	22.60	391.5	24.5	

Notes 1. Reference GE Heat Balance (5920-11399 -Sht. 2 of 19)
2. Reference GE Task Report T0700 Figure 3-1 120% of CLTP Rated Heat Balance
3. CLTP based on 2 FDW pumps running, CPPU based on 3 FDW pumps running.

EMCB-C 3

In Section 3.11 of Attachment 6 to the submittal dated September 10, 2003, the licensee addresses the Reactor Water Cleanup System (RWCS) evaluation. The staff requires the following additional information:

a. By how much does the temperature in the RWCS decrease after the EPU?
b. What is the expected increase of iron input to the reactor caused by a higher feedwater flow?
c. In the submittal, the licensee stated that its review of the RWCS functional capability has indicated that during EPU the system can adequately perform with the original RWCS system flow. Provide a basis for this conclusion.

Response:

a. The inlet temperature in the RWCS after CPPU decreases by 1.7°F from 527.6 °F to 525.9 °F.

b. The calculated percentage increase in reactor water iron concentration from 16.87 PPB to 20.67 PPB is 22.5%. The feedwater iron flow increased due to the feedwater flow increase. The calculated iron flow rate increases from 0.0077 lbm/hr to .0095 lbm/hr.

c. RWCU flow is usually selected to be in the range of 0.8% and 1.0% of feedwater flow based on operational history. The existing RWCU flow (and that analyzed for CPPU) of 68,000 lbm/hr is within this range. Further more, the CPPU review included evaluation of water chemistry, heat exchanger performance, pump performance, flow control valve capability and filter/demineralizer performance. All aspects of performance were found to be within the design of RWCU at the analyzed flow.

The RWCU analysis concludes that:

- There is negligible heat load impact
- A small increase in filter/demineralizer backwash frequency will occur, but within the capacity of the Radwaste system
- The slight changes in operating system conditions results from a decrease in inlet temperature and increase in feedwater system operating pressure
- The RWCU filter/ demineralizer control valve will operating in a slightly more open position to compensate for the increased feedwater pressure
- As identified in the PUSAR summary for RWCU, iron concentration and water conductivity are expected to increase slightly but will be within existing, allowed ranges

EMEB-B 1

Sections 3.5 and 4.1.2, of Attachment 6 to the submittal dated September 10, 2003, provide a discussion of the evaluation of piping systems attached to the torus shell, vent penetrations, pumps, and valves, that are affected by increased torus temperature and changes in loss-of-coolant accident (LOCA) dynamic loads (pool swell, condensation oscillation, and chugging) and increased temperature and flow in the main steam and feedwater systems due to the proposed power uprate. Identify supports and piping systems affected by required modifications stated in Attachment 3 of the submittal, as a result of the proposed EPU.

Response:

For Reactor Coolant Pressure Boundary (RCPB) piping systems, the two pipe supports requiring modification are identified in Section 3.5.1. Specifically, main steam pipe supports MS-35 and MS-6 are identified as requiring minor modifications.

For Balance of Plant (BOP) piping systems, the one pipe support requiring modification is identified in Section 3.5.2. Specifically, reactor core isolation cooling (RCIC) pipe support RCIC-HD63C is identified as requiring a minor modification.

Design changes to the high-pressure (HP) turbine will increase the operating pressure in the cross-around piping to the low-pressure turbines. The cross-around relief valves are installed to protect the cross-around piping and Moisture Separators from over pressurization should the down stream control valves close causing the cross-around piping to over pressurize. New relief valves and accompanying piping hardware are being installed to increase discharge capacity. No new pipe supports are being installed.

EMEB-B 2

Section 3.5.2, of Attachment 6 to the submittal dated September 10, 2003, provides a summary addressing your evaluation of the effects of the proposed power uprate on the BOP piping, components, and pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchorages. Also, provide the calculated maximum stresses and fatigue usage factors for the most critical BOP piping systems, the allowable limits, the code of record and code edition used for the power uprate conditions. If different from the code of record, justify and reconcile the differences.

Response:

The calculated maximum stresses and allowable stress limits for the most critical Balance of Plant (BOP) piping systems are provided in Tables 3-8a, 3-8b and 3-8c. Table 3-8a provides the maximum stresses and allowable stress limits for feedwater, extraction steam, feedwater heater vents and drains, and condensate piping systems. Table 3-8b provides the maximum stresses and allowable stress limits for torus attached piping systems. Table 3-8c provides the maximum stresses and allowable stress limits for the main steam system. Fatigue usage factors are not included in the Vermont Yankee (VY) design basis for BOP piping evaluations.

The power uprate piping evaluations were performed to the current VY codes of record. No new codes were used in the power uprate piping evaluations, hence, no code reconciliation was required.

EMEB-B 3

On page 3-15 of Attachment 6 to the submittal dated September 10, 2003, it states that a qualitative evaluation was performed that identified preliminary modifications and inspections to enhance the structural integrity of the steam dryer at CPPU conditions, and that a quantitative evaluation to identify dryer components susceptible to failure at CPPU conditions is being performed. The licensee should describe those evaluations and their results, and the schedule for implementing identified modifications. The licensee should also describe its evaluation of the recommendations in General Electric (GE) Service Information Letter (SIL) No. 644, Revision 1, "BWR Steam Dryer Integrity," and its commitments regarding implementation of those recommendations.

Response:

The VYNPS Steam Dryer is a BWR-3 style dryer with internal braces in the outer hoods. For the 120% power uprate application for VYNPS, a quantitative evaluation of the effects of Flow Induced Vibration (FIV) on the steam dryer has been completed to determine modifications that are required prior to CPPU implementation. The following sections describe the process and the quantitative results of the evaluation. Sections 1 through 4 describe the evaluation process and load definition process as applied to VYNPS. Sections 5 through 8 describe the key inputs from design documentation, input assumptions, and quantitative results. Section 9 describes VYNPS actions with respect to GE Service Information Letter (SIL) 644, Supplement 1. Section 10 describes the planned modifications to the VYNPS steam dryer and schedule for modification implementation.

1. Steam Dryer Flow Induced Vibration (FIV) process

- For Extended Power Uprate, GE has developed a process to evaluate the steam dryer dynamic vibration response. The method is termed "Equivalent Static Analysis Method." The Equivalent Static Analysis Method consists of the following process steps:
- A Finite Element Analysis (FEA) model of the VYNPS steam dryer was developed (see Section 2). This model was constructed using VYNPS specific dryer dimensions and material properties.
- The FEA computes steam dryer component natural frequencies and mode shapes (see Section 3).
- A reference [[ ]] static pressure load is applied in the FEA model. Steam Dryer component Membrane (Pm) and Surface (Pm + Pb) stresses are computed from the [[ ]] reference load.
- Dynamic loading on the steam dryer components is computed via the following equation:

  DL = (Pm+Pb) x (FIV Load rms) x (P) x (AF) x (C)

  Where:

  DL = Dynamic Loading (psi)

  Pm+Pb = Surface stress computed from [[ ]] reference load in FEA model

  FIV Load rms = Fluctuating load (Root-mean-squared (rms) load factor) computed from plant data and scaled to VYNPS steam velocity conditions. See Section 4 for the determination of the fluctuating load for VYNPS.

  P = Conversion factor from RMS to Zero-to-Peak (0-P). A factor of [[ ]] is used.

  AF = Amplification Factor or Dynamic Load factor. Factor can vary from [[ ]]depending on the degree of matching between a natural frequency and a spectral peak.

  C = Stress Concentration Factor. A value of [[ ]] is used.

- A screening process is used to identify components that are susceptible to stress fatigue failure at both CLTP and EPU conditions. The screening process applies an AF of [[ ]]since this implies close frequency matching conditions and results in the highest dynamic loading (peak stresses). Components that exceed the fatigue failure criterion are then further evaluated.
- Components that fail the initial screening process are further evaluated. The evaluation process assumes that the components have not failed at OLTP/CLTP conditions and, therefore have a peak stress value no larger than fatigue failure criterion (27,200 psi). This assumption is considered appropriate since there is no evidence that the components have failed at CLTP conditions. The amplification factors (AF) are back-calculated from the high stressed components using the following equation:

$$AF = \frac{27{,}200}{(Pm + Pb)(FIVLoadrms)(P)(C)}$$

- The EPU stresses are then recalculated using the revised AFs and then compared to the acceptance criterion. The highest value of AFs thus obtained is used to re-calculate CLTP and EPU stresses for remainder of the components in the low to moderate stress range.

2. Steam Dryer FEA model

- Dryer natural frequencies and stresses were calculated via finite element analyses of the dryer using the ANSYS finite element code Version 6.1. The dryer structure is dynamically isolated from the dryer skirt by the support ring. This is a result of the stiff support ring structure with its large cross-section, cross bracing from the dryer support plates, and bottom beams. Therefore, the analyses were limited to the dryer excluding the skirt.
- The finite element analysis model is shown in Figures 5, 6, and 7. The model includes the dryer support ring and cross-beams modeled with solid elements, and beam gussets, base-plate, drain troughs, dryer hoods, and the steam dam above the dryer with its support gussets, all modeled with shell elements. The dryer vane bundles are modeled as plates with sufficient stiffness for them not to interact with vibration modes of the dryer structure. The hood support braces and tie-bars are modeled as rectangular beams with section area and modulus equal to the section properties of these components. The model includes the rectangular gusset plates used to attach the diagonal braces to the hoods.
- Components, with the exception of the dryer vanes and the support ring, were modeled to represent their masses based on as-drawn dimensions and a material density of 0.29 lb/in^3. Density of the plates representing the dryer vanes was adjusted to represent the weight of the dryer vanes.

3. Steam Dryer Frequency Calculations

- The dryer support from the RPV dryer support brackets was modeled by fixing all degrees of freedom at the support ring bottom surface nodes at these locations.
- The dryer hood plates are welded to the dryer vane top plates and the vertical braces at a few discrete points. There will be a gap between the edge of the hood plates and the top plates of the vanes. Impact at these gaps will not permit resonance of the hood plates as free-edged plates. Therefore the hood and vane top plates were assumed connected when performing frequency calculations. The plates were separated when performing pressure stress calculations.
- The baffle plates (flow diverter plates at the dryer centerline) have a first mode frequency of [[ ]]. The outer hood vertical plates have a first mode frequency of [[ ]]. With the comparable dimensions of the plates, there is a vibration mode every few Hz above the fundamental frequency values that is applicable to one of these plates. Considering distribution of the potential pressure fluctuations, it would be difficult to excite modes higher than the first two modes of these plates. Therefore only the first two modes of the plates are of interest which are limited to 0-50 Hz.
- None of the horizontal plates (cover plates, hood top plates, dryer vane support plates) are excited in the 0-70 Hz range. Actually it was not possible to excite the horizontal plates without simultaneous excitation of the attached vertical plates or the dryer support ring. Therefore no specific vibration frequency could be identified for the horizontal plates. Therefore, for stress estimation, excitation frequencies for the horizontal plates were based on the excitations frequencies for the attached vertical plates. An exception was made in the case of the outside cover plates because of its failure experience at Quad Cities Unit 2. Frequencies were calculated for the outer cover plates assuming the plates to be stand-alone components fixed at the boundaries.

4. Fluctuating Load Definition

VYNPS plant specific data for dryer pressure loading is not available. GE has developed a process whereby available steam dryer pressure loading plant data has been converted into a reference load distribution versus frequency plot that can be further scaled for plant-specific evaluation use.

4.1 Overall Process

- The reference load definition is based on all the available in-plant pressure measurements from instrumented steam dryers. The reference load definition used detailed pressure versus frequency spectrums taken from in-plant measurements for one domestic GE BWR and two foreign GE BWRs. The measured spectrums for each sensor were adjusted for sensor location to determine an effective pressure at the dryer hood vertical face. The maximum sensor readings were plotted together. The spectrum was divided into frequency zones based on the general characteristics and peaks within the zone. Observations from an additional two domestic GE BWRs and one foreign GE BWR were used to further define the frequency zones. The magnitude of the reference load was set equal to the peak value within the zone. For plant-specific applications, scaling factors were determined for each frequency zone based on the plant steamline velocity compared to the reference plant steam velocity. [[ ]].

4.1.1 Reference Load Definition and Plant-Specific Scaling Process Steps

1. GE laboratory scale model test measurements were used to develop multipliers to adjust the plant signal readings from the plant measurement location (e.g., skirt, mast) to arrive at an effective pressure at the dryer vertical face. [[ ]].
2. The maximum of the sensor readings as a function of plant power level was found at each frequency for each plant sensor. This maximum was then multiplied by the appropriate multiplier ([[ ]]) to determine the equivalent vertical face pressure (Figure 2).
3. The adjusted maximums for each sensor were then plotted together on one plot. An envelope was drawn based on the maximum of all the sensor measurements. The spectrum was then divided into frequency zones based on the general characteristic and magnitudes of the peaks within the zone (Figure 3). The frequency zones also considered evidence from other plant measurements for which digitized plant measurement information was not available. [[ ]]. The magnitude of the reference load in each frequency zone was set equal to the maximum peak value within the zone. The steamline velocity for the plant setting the magnitude of the load was also identified as the reference velocity for scaling purposes.
4. [[ ]]
5. For plant-specific applications, the reference load in each frequency zone is scaled for each plant based on the ratio of the plant-specific steamline velocity to the reference steamline

velocity. [[

]]For plant-specific applications, the frequency zones remain the same as the reference load definition. The plant-specific load amplitude can be determined for each frequency zone by using the following equations:

[[

]]

- Scaling of Reference load amplitudes to VYNPS load amplitudes for both CLTP and EPU is shown in Figure 4.
- The common BWR plant steam piping layout and the resulting similarities in the measured in-plant test data justify the application of the generic load definition to VYNPS. There are two primary frequency zones of interest in the load definition: 0-55 Hz and 120-205 Hz. Because of the long wavelengths involved acoustic interactions in the main steamlines and equalizing header are the source of the pressure fluctuations observed in the 0-55 Hz range. VYNPS and the plants used in developing the generic load definition all have similar steamline configurations. The overall steamlines lengths at plants are typically between 200 to 500 feet. The fundamental frequencies corresponding to these lengths are 8 to 3 Hz, respectively. The frequencies defining the reference load in the 0-55 Hz range are consistent with higher harmonics of the steamline fundamental frequencies of 3-8 Hz. Since the defining frequencies are consistent with the higher harmonics over the range of steamline lengths, the overall plant steamline length is not critical in applying the generic load definition. In addition, all the plants have a large diameter equalizing header just upstream of the turbine. The pressure fluctuations in the 120-205 Hz range may be caused by smaller diameter branch lines (e.g., SRV, HPCI) in the main steam system, or by acoustic interactions between the steamlines and the chambers formed between the dryer and the steam dome. These branch lines and regions are common between VYNPS and the plants used to develop the generic load definition. As can be seen in Figure 2, the pressure responses for the plants used to develop the generic load definition are similar. The plant-specific pressure response for VYNPS would be similar to the response for these plants.

- In addition to the similarity in pressure response shown between the plants, a significant amount of conservatism is introduced by the peak broadening used in the generic load definition. Figure 3 compares the plant data with the reference load definition. Because of the broad frequency zones around the peaks exhibited in the plant data, it is not necessary to know the exact frequencies at which the peak pressures occur for VYNPS. The peak broadening will ensure that conservative loads are applied in the VYNPS dryer analysis.

- The generic load definition and scaling has been compared to the dryer loading determined in the Quad Cities 2 dryer failure root cause evaluation. In the Quad Cities 2 dryer failure root cause evaluation, the loading on the dryer was independently estimated based on in-plant test data (similar to the generic load definition), pressure measurements in a scale model test of the dryer/vessel/steamlines, and reverse-engineered fatigue calculations. When scaled to the Quad Cities operating conditions, the generic load definition predicts pressure loads that agree well with the other estimates [[
  ]]

Figure 1 VYNPS Steam Dryer Components

[[

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Figure 2 Steam Dryer Fluctuating Loads – Plant Data Maximum Pressures

[[

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Figure 3 Steam Dryer Fluctuating Loads – Reference Load Definition

[[

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Figure 4 Steam Dryer Fluctuating Loads – Reference Load Scaling to VYNPS

[[

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Figure 5 Dryer Model – Dryer Support Structure

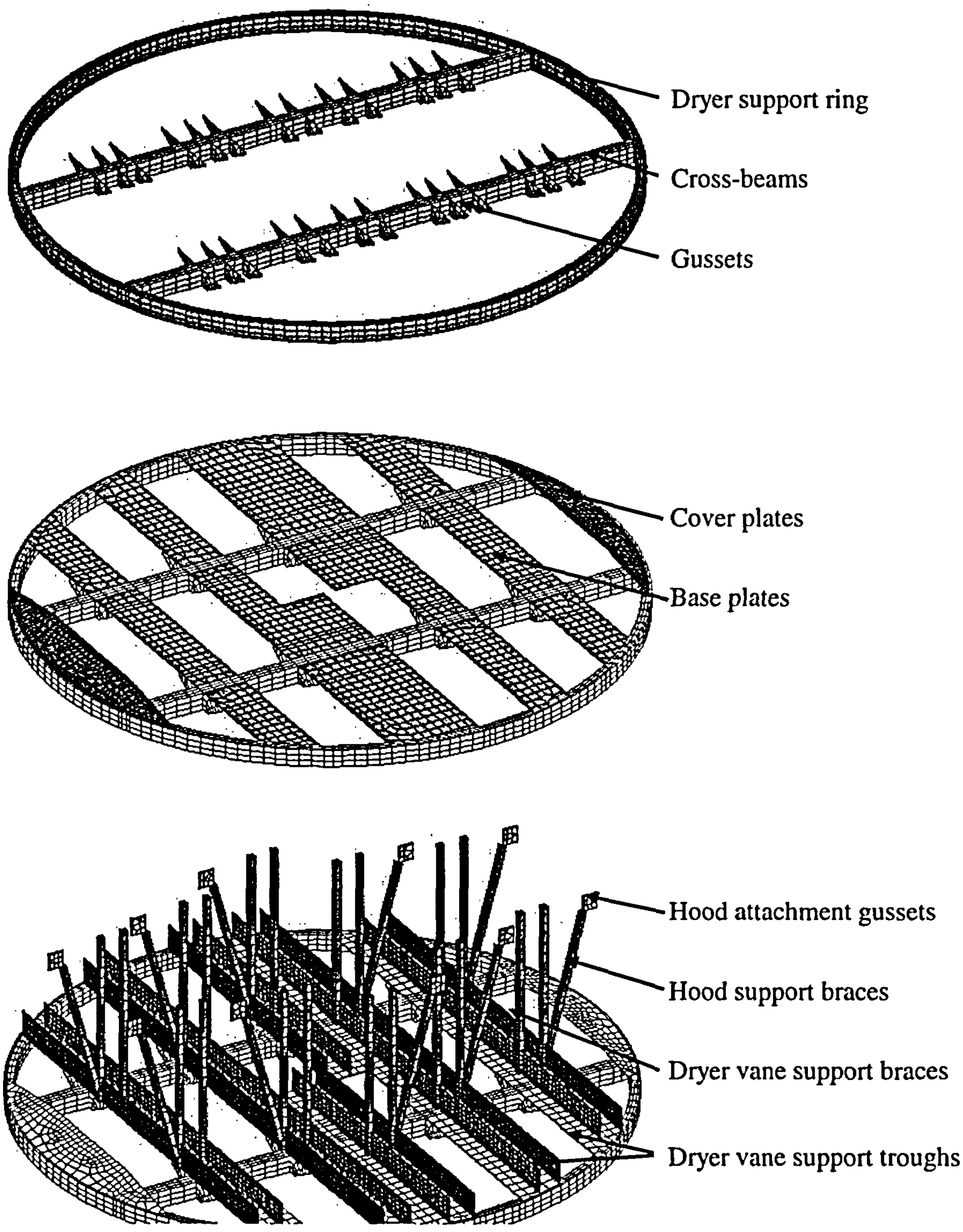


Figure 6 Dryer Model – Dryer Vertical Plates and Vane Simulation Plates

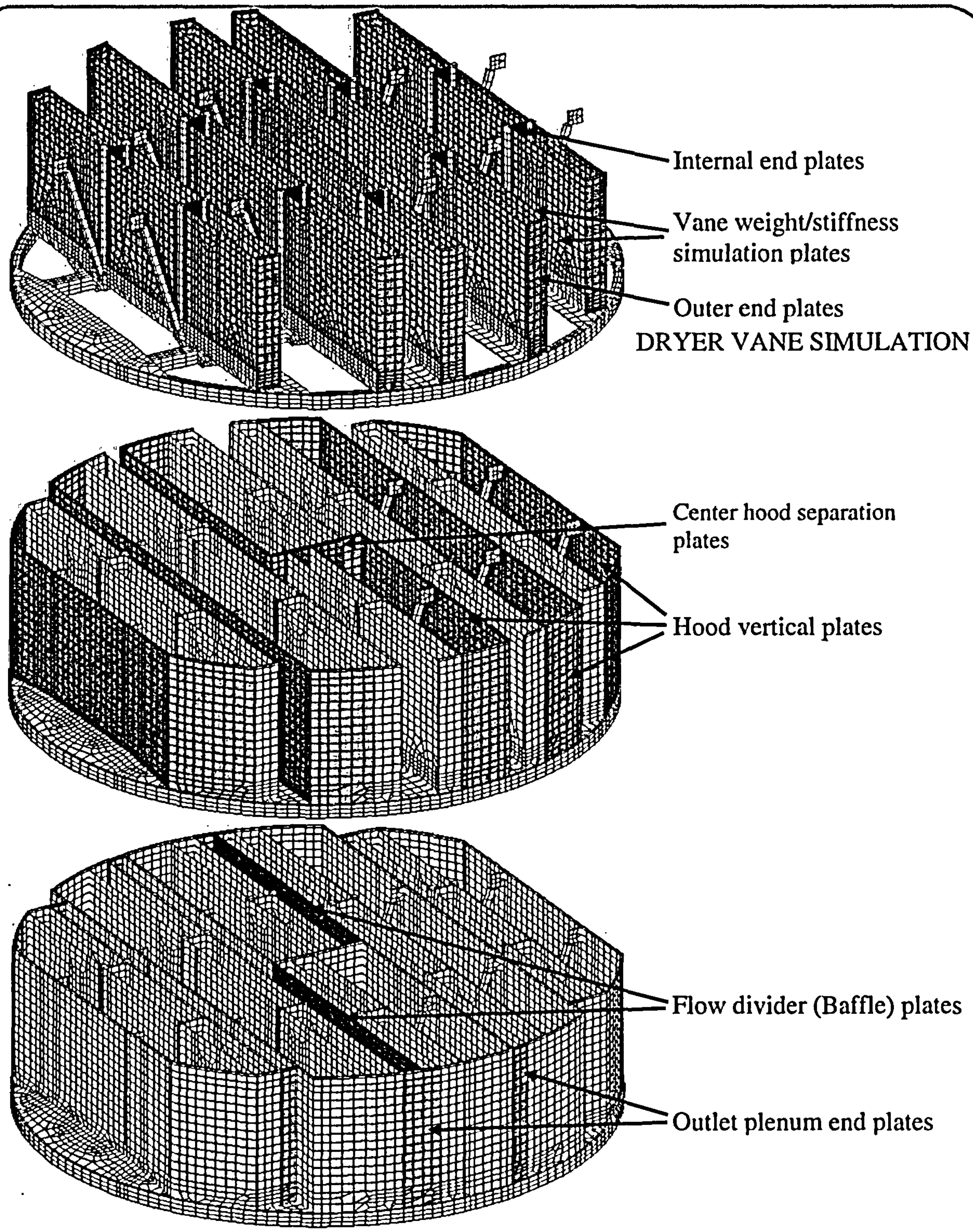
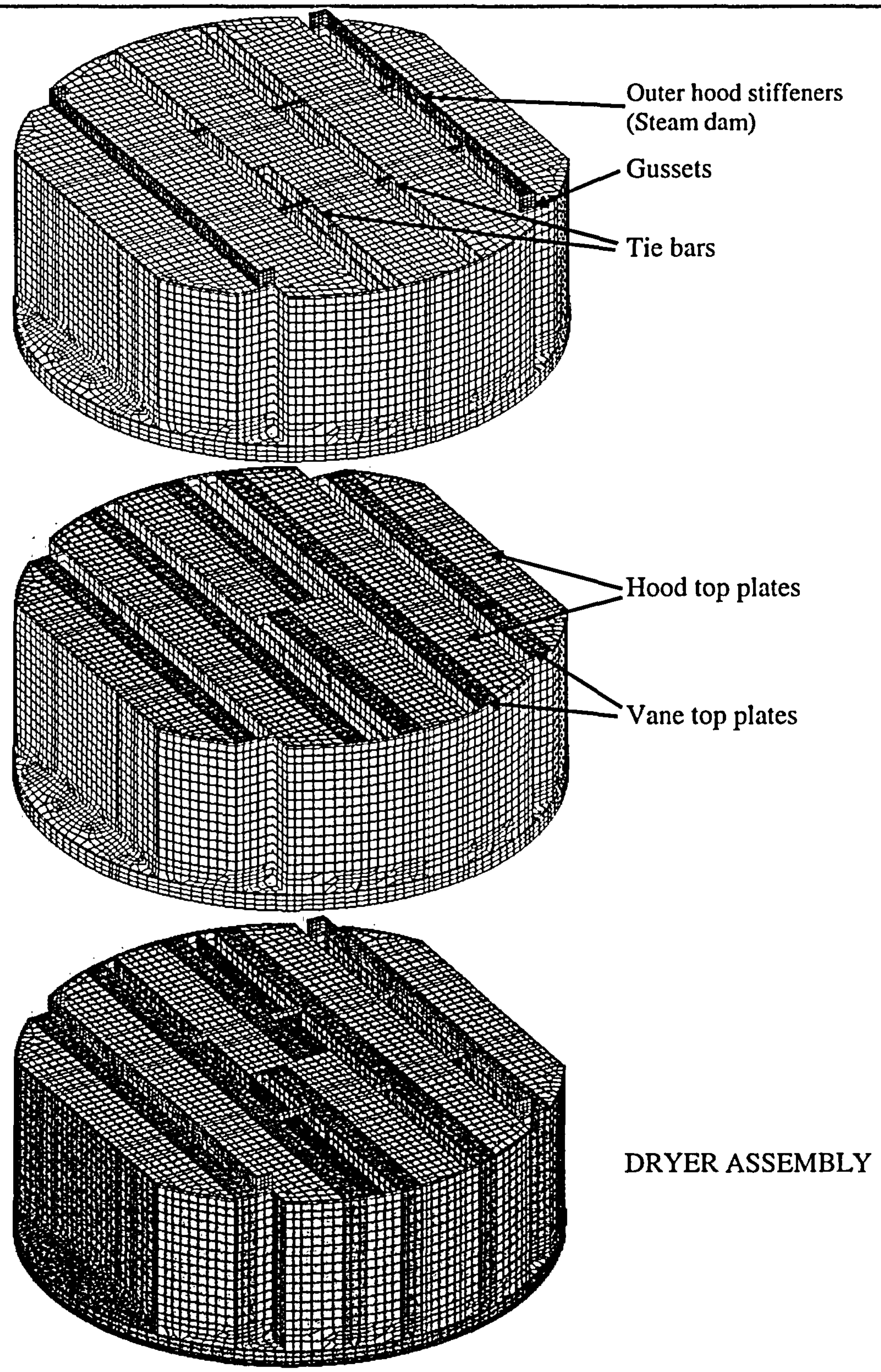


Figure 7 Dryer Analysis Model



5. Key Input for Steam Dryer Evaluation

Item	Key Parameter	Unit	CLTP Value	CPPU Value	Reference/Basis
1	RPV dimensions in steam path	NA	RPV design documentation validated by Entergy	Same	Design unchanged from CLTP to CPPU
2	Steam Dryer Dimensions	NA	RPV design documentation validated by Entergy	Same	Design unchanged from CLTP to CPPU
3	MS Flow Rate	Mlb/hr	6.458	7.906	Reactor Heat Balances
4	MS Flow Velocity	ft/sec	140	168	Computed from main steam flow rate, main steam pipe diameter and steam thermodynamic conditions

6. Fluctuating Load Input Calculation

Frequency Range (Hz)	Reference Plant Amplitude rms psi	Reference Plant Steam Line Velocity ft/sec	Maximum Scaling Exponent	Minimum Scaling Exponent	VYNPS CLTP Amplitude rms psi	Ref./Basis	VYNPS CPPU Amplitude rms psi	Reference/Basis
0 to 55								
55 to 120								
120 to 205								
205 to 320								
320 to 525								
525 to 800								

Notes: Amplitude values in above table are shown graphically in Figure 4.
VYNPS CLTP Plant Specific (PS) Steam Line Velocity = 140 ft/sec
VYNPS CPPU Plant Specific (PS) Steam Line Velocity = 168 ft/sec

*VYNPS amplitudes are obtained from the following equations. The development of these equations is discussed in Section 4.1.1:

[[

]]

7. Key Assumptions

Item	Assumption	Reference/Basis
1.	For the determination of fluctuating loads, the acoustic peaks in the measured data are fully developed and that no new peaks will form and exceed the existing peaks. Similarly, it is assumed that the resulting maximum amplitude curve is representative of any plant.	These assumptions are based on a qualitative observation of the measured plant data for three domestic and three foreign GE BWRs. This assumption is further validated by the similarity in all plants, including VYNPS, of steam line lengths, use of large steam line equalizing headers upstream of the main turbine inlet, and similar steam line branch line configurations. (Section 4)
2.	For the determination of fluctuating loads, it is assumed that the frequencies of the acoustic peaks, when broadened over a limited band, are representative of all BWRs.	This assumption is based on a qualitative observation of measured plant data. The uncertainty in the plant-specific frequency for any given peak is addressed by defining the frequency zones in the reference load curve (Section 4).
3.	For the determination of fluctuating loads, it is assumed that the maximum amplitudes are related to the steamline velocity	This assumption is supported by the frequency content in the plant measurement data (Section 4). The flow velocity is the governing operating parameter in acoustics. The acoustic peaks in the 25 Hz range of plant specific fluctuating load data are associated with wavelengths of about 64 feet (assuming a speed of sound in steam of 1600 ft/sec). These wavelengths are too large to come from inside the reactor vessel.
4.	The GE plant-specific scaling of fluctuating loads based on the average amplitude within a frequency zone is appropriate.	This assumption is derived from the previous assumptions (Items 1, 2 and 3) that the acoustic peaks are fully developed, no new acoustic peaks will form, and that the maximum amplitudes are governed by the steamline velocity.
5.	A stress failure acceptance criterion of 27,200 psi is used for assessment of steam dryer components. This value is twice the ASME curve C (ASME Section III, 1986, Division 1, Appendix I, Figure I-9.2.2, Design Fatigue Curve for Austenitic Steels) value.	The VYNPS steam dryer is a non-safety related component and, while is considered robust, was not originally designed nor rigorously analyzed for the effects of FIV. Therefore it is considered appropriate that a value of twice the ASME design fatigue curve is used to represent the mean of the failure curve. The ASME criteria for service cycles equal to 10^{11} are given in ASME Section III, 1986, Division 1, Appendix I, Figure I-9.2.2, Design Fatigue Curve for Austenitic Steels.

Item	Assumption	Reference/Basis
6.	The conversion from Root-Mean-Squared (rms) to 0-P is [[ ]] times the rms value (0-P = [[ ]]x rms)	This is based on GE experience for reactor internal vibration testing at over 20 plants and has been used as a standard conversion factor for rms to 0-P conversion in other EPU evaluations.
7.	A stress concentration factor of [[ ]] is used in the steam dryer analysis.	This factor is based on ASME assessments used in conjunction with finite element analyses to address the weld quality factor. It is used for both butt and fillet welds.
8.	Dynamic load factors range from [[ ]]minimum to [[ ]] maximum	These factors were obtained by comparing time history dynamic analysis results with static analysis results. Higher factors result when the forcing frequency is close to the natural frequency of the component. It is recognized that at resonance, the amplification can exceed the value of [[ ]] in that the structure's response could potentially be reinforced to higher levels. However, the actual geometry of the component is complex and the peak amplitudes do not occur every cycle. They in fact would be expected to occur much less frequently, on the order of every 0.5 Hz at worse. To support the assessment of this type of loading, studies were undertaken by GE to input actual time history pressure loading that had variable amplitude levels. The resultant amplification factors were found to range from [[ ]]depending on the proximity of the driving frequency to the structural frequency in a detailed smaller model. These analytical results were used as the basis for the maximum factor of [[ ]] being used to assess the dynamic amplification factor for bounding field case conditions in the more complex dryer structure.

8. Evaluation Results

8.1 Steam Dryer Component Associated Frequencies and Stresses for [[ ]] Uniform Reference Load

Item	Component (See Figure 1 for Location)	Surface stress (Pm +Pb), psi,	Associated Frequency Hz	Notes (See Section 3 for discussion)	VYNPS CLTP Amplitude rms psi	VYNPS CPPU Amplitude rms psi
1.	Base plate	[[		Part of Stiff Base Structure. Estimated Very High Frequency	[[	
2.	Outer cover plate			Stand Alone Natural Frequency		
3.	Outer cover plate			Vertical Plate Driving Frequency		
4.	Hood top plates			Vertical Plate Driving Frequency		
5.	Hood vertical plates			Natural Frequency		
6.	Hood end plates			Mixed 27th Vibration Mode		
7.	Hood end plates			Vertical Plate Driving Frequency		
8.	Hood bracing brackets (gussets)			Vertical Plate Driving Frequency		
9.	Hood below cover plate			Vertical Plate Driving Frequency		
10.	Steam 'dam'			Mixed 73rd Vibration Mode		
11.	Steam 'dam' gussets			Stiff. Estimated Very High Frequency		
12.	Hood partition plates			Stiff. Estimated Very High Frequency		
13.	Baffle plates			Natural Frequency		
14.	Outlet plenum ends			Stiff. Estimated Very High Frequency		
15.	Dryer support ring			Part of Stiff Base Structure. Estimated Very High Frequency		

Item	Component (See Figure 1 for Location)	Surface stress (Pm +Pb), psi,	Associated Frequency Hz	Notes (See Section 3 for discussion)	VYNPS CLTP Amplitude rms psi	VYNPS CPPU Amplitude rms psi
16.	Bottom cross beams			Part of Stiff Base Structure. Estimated Very High Frequency		
17.	Cross beam gussets		]]	Part of Stiff Base Structure. Estimated Very High Frequency		]]

8.2 Steam Dryer Component FIV Stresses – Screening Process with Maximum Amplification Factor (AF)

Item	Component	CLTP Dynamic Loading (psi)	Acceptable against Fatigue Failure Criterion	CPPU Dynamic Loading (psi)	Acceptable against Fatigue Failure Criterion	Further Evaluation Required for CPPU
1.	Base plate	[[	Yes	[[	Yes	No
2.	Outer cover plate (1)		No		No	Yes See Section 8.3
3.	Outer cover plate (2)		No		No	Yes See Section 8.3
4.	Hood top plates		Yes		No	Yes See Section 8.3
5.	Hood vertical plates		No		No	Yes See Section 8.3
6.	Hood end plates (3)		Yes		Yes	No
7.	Hood end plates (2)		Yes		No	Yes See Section 8.3
8.	Hood bracing brackets (gussets)		No		No	Yes See Section 8.3
9.	Hood below cover plate		Yes		Yes	No
10.	Steam 'dam'		Yes		Yes	No
11.	Steam 'dam' gussets		Yes		Yes	No
12.	Hood partition plates		Yes		No	Yes See Section 8.3
13.	Baffle plates		Yes		Yes	No
14.	Outlet plenum ends		Yes		Yes	No
15.	Dryer support ring		Yes		Yes	No
16.	Bottom cross beams		Yes		Yes	No
17.	Cross beam gussets	]]	Yes	]]	Yes	No

Note: Amplification Factor (AF) of [[ ]] is used for both CLTP and CPPU calculation. See Section 7 item 8 for discussion.

(1) Stresses at Stand Alone Natural Frequency
(2) Stresses at Vertical Plate Driving Frequency
(3) Stresses in a Mixed Vibration Mode

8.3 Steam Dryer Component FIV Stresses – Critical Components

Item	Component	Amplification Factor (AF)	CLTP Dynamic Loading (psi)	CPPU Dynamic Loading (psi)
1.	Outer cover plate (1)	[[		
2.	Outer cover plate (2)			
3.	Hood top plates			
4.	Hood vertical plates			
5.	Hood end plates			
6.	Hood bracing brackets (gussets)			
7.	Hood partition plates			]]

Note: (1) Stresses at Stand Alone Natural Frequency

(2) Stresses at Vertical Plate Driving Frequency

(3) Amplification Factor calculated that causes CLTP stress to reach acceptance criterion of 27,200 psi

(4) Maximum of Amplification Factors obtained for Item 1, 2 and 4 applied to compute stress.

9. VYNPS evaluation of the recommendations in General Electric (GE) Service Information Letter (SIL) No. 644, Supplement 1, "BWR Steam Dryer Integrity."

The VYNPS steam dryer is a BWR-3 style dryer (square hood) with inner braces in the outer hoods. GE SIL 644, Supplement 1 provides the following recommendations concerning this steam dryer design with respect to flow induced vibration at power uprate conditions.

1. Review available visual inspection records to determine if there are any pre-existing flaws or undersized welds in the cover plate and outer hood locations.

VYNPS Action:

Available visual inspection records of the VYNPS steam dryer do not indicate any pre-existing flaws in the cover plate and outer hood locations. Previous inspections of the VYNPS steam dryer assembly have been limited to the steam dryer outer surfaces. Entergy is planning to perform an augmented visual inspection of both the external and internal steam dryer surfaces during the cycle 24 refueling outage in April 2004 as specified by SIL 644, Supplement 1.

2. Measure moisture content, as determined by Na-24 measurements in the reactor water and condenser hotwell, to establish a baseline value for operation near maximum core thermal power operating conditions. Measure and record the moisture content to a resolution of 0.1% or smaller. Isolate (or account for) flow through paths where reactor water can flow directly to the hotwell (e.g., reactor water cleanup reject flow, sample lines).

VYNPS Action:

VYNPS presently has a periodic monitoring program for steam moisture content. The CLTP moisture content is typically on the order of 0.04wt/%. This value is well below the original steam dryer performance specification value of less than or equal to 0.1wt/%. The calculated steam moisture content at CPPU conditions is less than 0.08%.

3. Monitor reactor pressure, water level, individual steamline flow, and feedwater flow on a daily basis for significant anomalies (such as step changes in indicated values) that may indicate a steam dryer failure. Monitor and compare indications on each instrument reference leg; a dryer failure near the reference leg tap may affect the indications for the sensors on that reference leg. The step changes that were observed during the 2002 cover plate failure were usually small (2-3 psi for reactor pressure, ~two inches for reactor level,~5% for steamline flow); therefore, trend plots of the data will be useful for performing the recommended monitoring.

VYNPS Action:

VYNPS plans to develop a moisture carryover/dryer integrity monitoring program that encompasses the parameters discussed in the SIL. The trends in the above parameters can be compared with changes in the carryover to note potential indications of dryer problems.

4. Implement a moisture content monitoring program that measures moisture content at least once per week. If a significant change or a steadily increasing trend is observed, monitor moisture content daily and evaluate recent plant maneuvers or events and associated plant parameters to identify the cause of the increased moisture content. If the cause of the increased moisture content cannot be determined, consider a reduction in power or an orderly plant shutdown for inspection.

VYNPS Action:

VYNPS currently monitors-moisture carryover on approximately a weekly basis. As previously noted VYNPS plans to develop a moisture carryover/dryer integrity monitoring program that trends a number of different parameters, along with carryover, in an attempt to identify potential dryer problems.

5. Perform a visual inspection ("best effort" VT-1) of the steam dryer at the next scheduled refueling outage. This inspection should include the most susceptible locations as determined by a dryer stress analysis (refer to Figure 4 of SIL). This inspection should include both an external and internal inspection of the accessible areas. Remove trapped bubbles to ensure complete coverage of internal areas.

VYNPS Action:

VYNPS will perform a baseline visual inspection as specified by SIL 644, Supplement 1 of the VYNPS steam dryer, both external and internal, in the cycle 24 refueling outage prior to planned CPPU implementation.

6. Repeat the visual inspection in subsequent refueling outages.

VYNPS Action:

VYNPS will repeat the steam dryer visual inspections in the refueling outages after CPPU implementation as recommended by the repair vendor and/or the BWROG/BWRVIP.

10. Extended Power Uprate Dryer Modification Plan and Schedule for Dryer Modification Implementation.

The following modifications to the VYNPS steam dryer are currently being designed by GE in order to ensure acceptability of the dryer at CPPU operating conditions:

1. Replace dryer lower cover plates (dryer 90 degree and 270 degree azimuths) with 0.5 inch thickness plate with 0.5 inch welds. The original lower cover plate is constructed of 0.25 inch thickness plate with 3/16 inch welds.
2. Replace the upper thirty inch section of the 90 degree and 270 degree azimuth flat vertical hoods with 1 inch thickness plate. The original dryer vertical hood plate thickness is 0.5 inch.
3 Replace a fifteen inch section of the dryer upper cover plates (90 degree and 270 degree azimuth), where each upper cover plate intersects the flat vertical hoods with 1 inch thick plate
4. Remove inner hood bracing that attaches to the vertical dryer hoods
5. Install gussets (33 inch high) between the modified lower dryer cover plates and the unmodified section of the flat vertical dryer hoods.
6. Install dryer bank tie bar reinforcements.

The modified VYNPS steam dryer is analyzed using the process described in Section 1 of this response. In addition, the fatigue loading acceptance criterion for the modified steam dryer is 13,600 psi, corresponding to the ASME Section III, 1986, Division 1, Appendix I, Figure I-9.2.2, Design Fatigue Curve for Austenitic Steels. Entergy will install the steam dryer modifications in the plant refueling outage prior to planned operation at Extended Power Uprate conditions, April 2004.

EMEB-B 4

On page 3-23 of Attachment 6 to the submittal dated September 10, 2003, it states that the increase in steam flow rate under CPPU conditions will assist in the closure of the Main Steam Isolation Valves (MSIVs) at VYNPS. The licensee indicates that the self-compensating feature of the hydraulic control valve will maintain the closing time with little deviation despite the flow change. The licensee should describe the MSIVs, the design feature that will ensure that MSIV closure time is not reduced below the stroke-time limit, and any testing or operating experience from plant-specific or generic sources that supports its determination that closure time will remain within the allowable limits.

Response:

The Vermont Yankee (VY) MSIV has design features that ensure the MSIV closure time is not reduced below the stroke time limit. The closing time of the MSIVs is controlled by the design of the hydraulic control valves and the function of the damper. Prior to CPPU implementation, the hydraulic control valve of the MSIV will be adjusted for the required closing time. See also Attachment 7 to the submittal dated September 10, 2003 page 4, the section titled: "Item 2: MSIV Closure Time."

The hydraulic damper senses the combined driving force of the pneumatic cylinder, the external closing springs, the steam drag force, the dead weight of the moving components and the friction force. The steam drag force applied on the main disc increases due to an increase in steam flowrate. This force change is transmitted from the main disc to the valve stem, and then to the connecting hydraulic damper rod. It is then transmitted to the hydraulic damper and the hydraulic control circuit. As the driving force increases due to the higher steam flowrate, a spring inside the hydraulic control valve would reduce the opening of an internal variable orifice in order to compensate the higher closing force. The net driving force would stay unchanged due to this compensating mechanism. The self-compensating feature of the hydraulic control valve will maintain the closing time with little deviation despite the flow rate change.

Other plants that have implemented CPPU similarly equipped MSIVs have not reported anomalies with MSIV closing time.

EMEB-B 5

On page 4-6 of Attachment 6 to the submittal dated September 10, 2003, the licensee indicates that it evaluated the Generic Letter (GL) 89-10 motor-operated valves (MOVs) at VYNPS for the effects of the CPPU, including those related to pressure locking and thermal binding per GL 95-07. The licensee reports that there were no changes to the design functional requirements of the MOVs. The licensee states that it did identify minor process fluid condition changes and increased ambient room temperatures for some MOVs. The licensee indicates that it will evaluate the affected MOVs through MOV program calculation updates with any resulting changes in current MOV settings implemented prior to CPPU operation. On page 4-7, the licensee reports that air-operated valves (AOVs) were reviewed to identify AOVs potentially affected by CPPU conditions. The licensee states that evaluation of affected AOVs may identify setting changes or modifications that will be accomplished prior to CPPU implementation. The licensee should describe the status, methodologies, and results of those MOV and AOV evaluations, and describe any planned setting changes or modifications. The licensee should also clarify: (1) the effect of the power uprate on the potential for thermal binding or pressure locking, such as caused by temperature increases, on the scope of power-operated valves under GL 95-07 or the performance of those valves; and (2) any modifications or procedure changes necessary as a result of the power uprate to preclude thermal binding and pressure locking. Finally, the licensee should describe its plans to incorporate the results of its evaluation of MOV performance under CPPU conditions into its long-term program to periodically verify the design-basis capability of safety-related MOVs in response to GL 96-05.

Response:

The VY Motor Operated Valve (MOV) program is established and implemented by administrative procedures. The implementation has resulted in the creation of calculation files for the system, component and electrical aspects of the MOV program. CPPU thermal hydraulic process conditions may affect a MOVs operational needs due to changes in:

- Line Pressure
- Differential Pressure
- Fluid Flow
- Fluid Temperature
- Normal Environmental Temperature
- Accident Environmental Temperature

All MOVs have been screened for impact by CPPU conditions. An example of the CPPU parameter changes calculated the affected Core Spray system valves in the screening process is:

	Mode(s)	Parameter Impacted	Current Value	CPPU Value
V14-5A	8	Line Pressure Differential Pressure Accident Environmental Temperature	52.6 psig 59.0 psid 155F	52.6 psig 59.0 psid 159F
	9- open	Line Pressure Differential Pressure Accident Environmental Temperature	355.6 psig 313.6psid 155F	355.6 psig 313.6 psid 159F
	9- close	Line Pressure Differential Pressure Accident Environmental Temperature	355.6 psig 348.7psid 155F	355.6 psig 348.7 psid 159F
V14-5B	8	Line Pressure Differential Pressure Accident Environmental Temperature	52.5 psig 58.9 psid 155F	52.5 psig 58.9 psid 159F
	9- open	Line Pressure Differential Pressure Accident Environmental Temperature	355.7 psig 313.7psid 155F	355.7 psig 313.7 psid 159F
	9- close	Line Pressure Differential Pressure Accident Environmental Temperature	355.7 psig 349.7psid 155F	355.7 psig 349.7 psid 159F
V14-7A	8	Line Pressure Differential Pressure Accident Environmental Temperature	54.3 psig 54.3 psid 155F	54.3 psig 54.3 psid 159F

Mode 8: Core spray Pump Seal Failure: MOVs Affected: V14-5A/B, V14-11A/B, V14-26A/B. Note that this mode of operation is not procedurally governed and may be considered a worst case maintenance isolation scenario.

Mode 9: Injection per procedure: MOVS affected: V14-5A/B, V14-12A/B, V14-26A/B

The only change for these valves was for Accident Environmental Temperature. Evaluation of MOV susceptibility to thermal binding/pressure locking (GL 95-07) is included in the MOV program. Valve susceptibility is identified in the system level calculations and a determination of valve acceptability is made in the component level calculations.

Any MOVs that are currently not susceptible to thermal binding or pressure locking will not become susceptible under CPPU conditions. VY valve evaluation guidance for thermal binding/pressure locking is based on the valve hardware characteristics, as influenced by system and environmental operating conditions. Of the valves previously identified that are subject to binding/locking; only RHR Drywell Spray Valve V10-26A, is calculated to experience an increase in accident conditions environmental temperature (5 °F). No hardware modifications are needed, however, this valve will be evaluated for the CPPU conditions and adjustments in accumulator setpoint made as necessary. Calculations associated with this setpoint will be updated accordingly. With the implementation of CPPU conditions in the MOV calculations and the setpoint modification noted above, all MOVs will be ready for CPPU operation. The MOV calculations are scheduled for completion June 30, 2004.

AOVs

The VY Air Operated Valve (AOV) program establishes the requirements and expectations for testing, inspection, maintenance and engineering evaluation of program AOVs. The purpose of the program is to provide a high level of confidence that all category 1 (active highly safety significant), category 2A (supports a safety significant function) and category 2B (important or critical to power generation) AOVs will perform their intended design function.

The CPPU AOV program review consisted of evaluating parameters that could adversely affect valve/operator operation. AOV program parameters that may be adversely affected by CPPU includes increases in operating differential pressure and shut off differential pressure. Conversely, changes in fluid operating flow rates and temperature would have minimal affect. Changes in control valve flow rates or decreases in operating differential would affect valve travel position but would have no affect on the AOV program requirements. Increases in flow rates through on/off or isolation valves would result in a proportional increase in developed pressure differential across the valve during flowing conditions but do not affect the AOV design shut off differential and therefore have no adverse affect on AOV program parameters.

Fluid temperatures, pressures and flow conditions for most systems do not change due to CPPU conditions. However, results of the evaluation show that there is an increase in inlet pressure, operating and shutoff pressure differential pressure for the high pressure feedwater heater drain valves and the moisture separator drain tank control valves. These changes in fluid conditions are being evaluated for affect on drain valve operators.

The AOV program procedures require that for Category 2A/2B valves, critical valve setup parameters are documented and available for testing. VY is reviewing the drain valve setup parameters for CPPU conditions using Kalsi Valve & Actuator Program (KVAP) and updating the calibration data sheets as required. These valves are scheduled for calibration in RFO 24 and the review/updates are scheduled to be completed March 31, 2004. Preliminary review does not indicate the need for equipment modifications.

EMEB-B 6

Beginning on page 4-7 of Attachment 6 to the submittal dated September 10, 2003, the licensee indicates that the performance of the ECCS at VYNPS will remain acceptable under CPPU conditions. In addition to this general discussion, the licensee should describe its evaluation of the effects of the CPPU on the performance of safety-related pumps; and any modifications or procedural changes related to safety-related pumps that might be necessary to accommodate normal plant operations under CPPU conditions or to support performance of their safety functions during design-basis events subsequent to implementation of the CPPU.

Response:

The evaluations of the ECCS were conducted for VY CPPU to confirm that the [[ ]] evaluation results documented in Licensing Topical Report (LTR) NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," are appropriate for VY CPPU. Those [[ ]]evaluations have been reviewed and approved by the NRC.

Attachment 6 documents that the [[ ]]evaluations associated with ECCS are applicable to VY. Additionally, the plant specific accident and transient analyses confirm the ECCS network remains adequate to assure acceptable post-uprate results. With these conclusions, it is determined that the performance of VY ECCS pumps will meet the CPPU requirements without any modifications or procedural changes.

Since the CPPU will result in an increase in peak pool temperature following a design basis accident, the NPSH and pump seals of RHR and CS pumps are potentially affected and thus require plant specific evaluations to address this issue. The evaluation of adequacy of NPSH available to the ECCS pumps is discussed in Section 4.2.6 of Attachment 6. As discussed on pages 3-26 and 4-9 of Attachment 6, the evaluation recommended that prior to the CPPU implementation, either the pump seals of the affected pumps be re-qualified, or a modification be completed to ensure seal operation under the increased peak suppression pool temperature. The seals have been re-qualified for the increased suppression pool temperature under accident conditions.

EMEB-B 7

On page 6-3 of Attachment 6 to the submittal dated September 10, 2003, the licensee notes that load changes on the DC power distribution system could include DC MOV load increases. The licensee should describe the potential DC MOV load increases resulting from the CPPU, and the impact of those load increases on DC MOV performance.

Response:

On page 6-3 of Attachment 6 to the submittal dated September 10, 2003, the following statement is made: "Load changes could include DC MOV load increases including NSSS..." This sentence was written to identify items potentially affected by CPPU that were evaluated for their effect on the DC power distribution system.

Regarding DC MOV load increases, potential load increases on the DC motor operated valves (MOV) can occur if there are increases in mechanical parameters such as system flow, pressure or temperature. The MOVs have been reviewed and there have been no system changes resulting from CPPU that would result in changes in load on the DC MOVs that would impact the loading on the DC power distribution system. Increases in environmental temperatures for the MOV's could affect DC MOV performance. A review of the areas the DC MOVs are located in indicate no substantial change in temperature that would affect MOV operation. The MOV program calculations are being updated to reflect CPPU conditions, however no physical changes are anticipated.

EMEB-B 8

On page 10-2 of Attachment 6 to the submittal dated September 10, 2003, the licensee states that operation at CPPU conditions will result in a slight increase in downcomer subcooling that may lead to increased flow rates for liquid line breaks. The licensee should describe the operation of the applicable pumps or valves under those increased flow rates, and any adverse performance effects.

Response:

The valve operation necessary to isolate the containment for a High Energy Line Break (HELB) break at CPPU conditions has been evaluated in Section 4.1.3 Containment Isolation and Section 4.1.4. Generic Letter 89-10 Program. The only pump operation that is potentially affected by the increased break flow rate is the pump that is connected to the broken piping. The analyses documented in Section 10.1 "High Energy Line Break" do not take credit for the operation of any pumps attached to broken piping in mitigating the consequences of the HELB.

IEPB-A 1

Supplement 3, dated October 28, 2003, provided an update to Attachment 3 of the September 10, 2003, submittal which addressed the licensee's EPU testing and modification plans. Attachment 3, page 21, states for STP 23 (feedwater system) and STP 24 (bypass valves), that testing is planned for CPPU. However the "Evaluation/Justification for Not Performing Test" column of the table states that testing is not required. Please provide clarification.

Response:

STP 23 (feedwater system): There are two aspects to this test. One is the feedwater pump trip and the other is setpoint and flow change testing. Setpoint and flow change testing, as discussed in the "Evaluation/Justification for Not Performing Test" column, is planned. The justification is provided for not performing the feedwater pump trip.

STP 24 (bypass valves) Justification is provided for not performing this test. Although this test is not required, testing of the bypass valves is currently planned during CPPU testing to evaluate increasing the test power level.

IEPB-B 1

Section 8.6, "Normal Operation Off-Site Doses," of Attachment 6 to the submittal dated September 10, 2003, states in the last paragraph, that the increased N-16 source at the turbine is due to lower decay times in transient, due to the higher steam flow rate and gives an expected increase of 26%. This percentage is then included in a maximum site boundary dose from all sources of 18.6 mrem. Provide a breakdown of this overall dose number. List all dose pathway components and describe the calculation method used, including all assumptions. Provide the present nominal value for the skyshine external dose component (before EPU) and the estimated value following EPU and identify the dose receptor for this skyshine component (i.e., is the dose receptor a member of the public located offsite (and therefore subject to the dose limits of 40 CFR 190) or a member of the public working onsite (subject to the dose limits of 10 CFR 20.1301)).

Response:

The annual dose of 18.6 mrem is the calculated maximum dose at the worst site boundary location from all external radiation sources, and is subject to the limits of 40CFR 190 (25 mrem per year from effluents and external shine) and the limits specified in the Vermont State Regulation Section 5-305 (20 mrem per year from external sources). The CPPU assessment performed to develop the estimated increase in the radiation levels and consequent annual off-site radiation dose to a member of the public located at the worst case site boundary location is summarized below.

A. The 26% increase of the skyshine source in the Turbine Building reflects: (1) a 20% increase of N-16 specific activity in the reactor steam (due to the higher partition factor of the generated N-16 in the reactor water to the steam phase caused by the increase of the core flow boiling fraction), and (2) a 4.6% increase of N-16 activity in the Turbine Building steam pipes due to faster steam travel velocity at CPPU conditions. See response to RAI Question 5 for details.

B. The dose pathways included are (1) the N-16 source in the Turbine Building, (2) radwaste stored in the North Warehouse, (3) radwaste on the Low Level Waste (LLW) Storage Pad, and (4) old turbine rotors and casings. The major dose contributor is the skyshine radiation from the N-16 source in the Turbine Building. The pre-CPPU and post-CPPU doses from the N-16 source and from other miscellaneous sources are summarized as follows:

B.1. Turbine Building N-16 Skyshine Dose at the Worst Site Boundary Location

The Vermont Yankee Nuclear Power Station (VYNPS) was treated with Noble Metal Addition (NMA) in April 2001. The NMA application will suppress the N-16 activity increase in the steam when the plant is operated with Hydrogen Water Chemistry (HWC) to mitigate the Inter-Granular Stress Corrosion Cracking. With NMA in place, the N-16 activity in the reactor steam will experience a brief spiking period during the power startup. The N-16 activity will return to a steady state baseline level when the reactor is operated at a constant power level. During HWC operation, hydrogen is injected to the feed water when the reactor is operated at or near the full power. At the beginning of the hydrogen injection, there will be another temporary N-16 spike in the reactor steam. Again the N-16 will gradually return to its baseline value for a constant power level and hydrogen injection rate. The N-16 activity level in the main steam is continuously monitored by the four Main Steam Line Radiation Monitors (MSLRM). The pre-CPPU site boundary dose due to N-16 skyshine includes three components: 1) the baseline dose corresponding to steady state power operation, 2) the dose increase due to the N-16 activity spike during reactor startup resulting from the NMA, and 3) the dose increase due to the N-16 activity spike during HWC startup.

The baseline dose at the current licensing thermal power was calculated based on the Offsite Dose Calculation Manual (ODCM) Equation No. 6-27a and the recorded MSLRM readings in year 2001 and 2002. To calculate the site boundary dose, the referenced ODCM equation utilizes the MSLRM readings and a correlation factor between the site boundary dose and the time integral of the average MSLRM reading. The correlation factor was established by *in situ* measurements during the months of May, June, and July of 2001 at the worst locations on the fence line, with Pressurized Ion Chambers, TLDs, and High Purity Germanium (HPGe) detectors. The calculated worst site boundary dose was then normalized to a value corresponding to 100% power using the Station Monthly Statistical Reports. The projected baseline dose at the current licensed power of 1593 MWt is 12.8 mrem per year.

The increase of the site boundary dose due to the reactor startup spike due to NMA was calculated based on the data collected at VYNPS during the fuel cycle 23 startup operation in May 2001. This dose increase was determined to be 0.16 mrem per startup at the CLTP.

The increase of the site boundary dose due to the HWC startup spike was calculated based on the composite data collected at VYNPS during the HWC system startup and benchmark tests in January 2002, and the operating experience at other plants. This dose increase was determined to be 0.438 mrem, per HWC startup with a 2-3 scfm hydrogen injection flow, at the CLTP.

The total annual site boundary dose due to the Turbine Building N-16 source at the current licensed thermal power is 12.8 mrem + 0.16 mrem + 0.438 mrem = 13.4 mrem, assuming 365-day full power operation, one reactor startup, and one HWC startup. Note that the dose increases due to reactor startup and HWC startup are relatively small. The dose increase due to multiple startups will be compensated by the lack of the N-16 source prior to the reactor startup.

As stated in part A of this response, the CPPU is expected to increase the N-16 activity in the Turbine Building main steam by approximately 26%. The post CPPU site boundary dose due to N-16 skyshine is projected to be 13.4 mrem x 1.26 = 16.88 mrem.

B.2. Site Boundary Doses from On-Site Miscellaneous Wastes

- Waste Stored in the North Warehouse

The nominal dose at the current licensing thermal power was calculated based on methodology discussed in the ODCM and the survey dose rates taken in the North Warehouse in year 2001. To calculate the site boundary dose, the ODCM methodology utilizes the survey dose rates and correlation factors between the site boundary annual dose and the measured dose rates at 1 meter from the sources. The calculated site boundary dose for year 2001 is 1.4 mrem. This dose is expected to increase by approximately 20% when all the stored wastes are generated at the uprate power.

- Stored Waste on the LLW Storage Pad

The nominal site boundary dose due to waste on the LLW Storage Pad is based on the 2001 value, which was also calculated with the ODCM methodology and the survey dose rates. The calculated site boundary dose at the current licensing thermal power is 0.0991 mrem. This dose is expected to increase by approximately 20% when all the stored wastes are generated at the uprate power.

- Old turbine rotors and casings in storage sheds

The direct dose at the west site boundary from the old turbine rotors and casings in storage sheds is based on the calculated value in January 1996, which was normalized to the measured dose rates at 3 ft from the storage building. The decay of the principle isotope, Co-60, was considered in the dose estimate. The calculated site boundary dose for year 2003 is 0.087 mrem. This dose will continue to decrease due to radioactive decay.

The total west site boundary dose from the on-site miscellaneous wastes at the current licensing thermal power is 1.4 mrem +0.0991 mrem + 0.087 mrem = 1.586 mrem. The projected post-CPPU dose is (1.4 mrem +0.0991 mrem) x 1.2 + 0.087 mrem = 1.886 mrem. VYNPS will implement an administrative limit for the maximum site boundary dose from these miscellaneous radwastes prior to implementation of power uprate. This administrative limit is 1.74 mrem/yr.

In summary, the calculated maximum pre-CPPU annual dose at the west site boundary from all external sources is 13.4 mrem + 1.586 mrem = 15 mrem. The projected maximum post-CPPU annual dose is 16.88 mrem + 1.74 mrem = 18.6 mrem.

IEPB-B 2

Section 6.3.3, "Radiation Levels," of Attachment 6 to the submittal dated September 10, 2003, states that the normal radiation levels around the spent fuel pool (SFP) may increase slightly, primarily during fuel handling operations. Explain the reason for and the magnitude of these postulated increases in dose rate levels in the area of the SFP. Verify that these postulated dose rate increases will be bounded by the current radiation zone designations in the SFP area. If this postulated dose rate increase is due to higher activation of spent fuel assemblies, discuss any effects that the storage of these spent fuel assemblies in the SFP may have on dose rates in accessible areas adjacent to the sides or bottom of the SFP.

Response:

Radiation levels in those areas of the plant which are directly affected by the reactor core and spent fuel will increase by the percentage increase in the average power density of the fuel bundles. Therefore, for a CPPU increase of 20% the radiation dose rates will increase by 20%. This is due to the increase in the bundle fission product inventory which is directly proportional to bundle power assuming sufficient time for the bundle to reach an equilibrium. Fuel enrichment, exposure (for fuel in core more than one cycle), and bundle design are only minor contributors with power density the dominate factor in fission product inventory.

The design of spent fuel pools is typically very conservative from the perspective of radiation exposure that changes in the fuel inventory/bundle surface dose rate of 20% result in inconsequential changes in operating dose. Surveys of the dose rate in areas around the spent fuel pool at Vermont Yankee show general dose rates less than 1 millirem per hour with some specific areas up to 2 millirem per hour. This is a decrease of over six orders of magnitude from the bundle surface dose rate. An increase of 20% would still result in general dose rates less than 1 millirem per hour with the highest rates running to 2.4 millirem per hour. Such changes will have little effect on plant operations or ALARA exposure.

IEPB-B 3

Section 8.3, "Radiation Sources in the Reactor Core," of Attachment 6 to the submittal dated September 10, 2003, states that access to vital areas needed for accident mitigation have been demonstrated to be less than 5 rem TEDE. Provide a list of vital areas requiring post-accident occupancy, including the plant's Technical Support Center, per NUREG-0737, Item II.B.2. For each of these vital areas, provide the calculated pre-uprate and post-uprate mission doses to an operator performing vital tasks following a LOCA. Specify the source term assumptions (e.g., core activity release timing assumed) in the post-CPPU/post-Alternative Source Term (AST) calculations.

Response:

The Vermont Yankee Radiological Vital Areas comprise 11 locations. The Alternative Source Term (AST) submittal addressed the Vital Radiological Area doses. First, three of the 11 locations that were subject to an inhalation pathway contribution were fully evaluated with the AST source term. The AST implementation further showed that the original TID-14844 source term remains bounding for Vital Radiological Area dose assessments. These evaluations are documented in POLESTAR Calculations PSAT3019CF.QA.08 and PSAT3019CF.QA.09 submitted with the AST application. The TSC calculation was also included in the AST submittal. The mission doses for the remaining eight (8) areas were scaled up-ward with consideration of the Extended Power Uprate (CPPU) power increase and fuel management changes since the original evaluation.

The original post-LOCA source term for Vital Radiological Area mission dose calculations assumed an instantaneous release of 100% of noble gases, 50% of halogens and 1% other solids (100/50/1) for a liquid source term composition. The use of 100% noble gases in the original liquid source term is overly conservative since it implies that core melt will take place within an intact and fully pressurized primary coolant system. It is also noted that, in the AST methodology, noble gases are specifically excluded from the post-LOCA liquid source term. The environmental gamma doses based on this source term assumed full power operation at 1665 MWt. The power scaling factor becomes 1950/1665 or 1.17 since the original calculation assumed a power level of 1665 MWt. Considering that the liquid source term in the current licensing basis included 100% of the noble gases, in addition to 50% of the halogens and 1% of the solids, the recommended adjustment factor of 1.2 is conservative.

The AST radiological source term calculation evaluated enrichment and burn-up combinations to maximize the inventory for each radionuclide in order to establish a bounding source term. This source term was utilized to evaluate the impact of both enrichment and exposure on the source term energy release rate. The undecayed photon spectra associated with the core actinides and fission products show that the bounding energy release rate (MeV/s) occurs at low enrichment (3.00 $^{w}/_{o}$) and low exposure (5 GWD/MTU). For vital area accessibility following short post-accident decay times, the increased enrichment and exposure for modern core designs will not result in an increase in the source term energy release rate. As a result, there is no scaling adjustment made for enrichment and exposure; that is, the scaling factors are unity.

An overall scaling factor is determined by combining the factors associated with power level, fuel enrichment and exposure:

$$F = 1.17 \times 1.0 \times 1.0 = 1.17 \cong 1.2$$

A summary of the vital areas, mission times, original dose results and CPPU results is provided in Table I on the next page. The external doses were originally reported as whole body (wb) dose. This becomes the basis for the CPPU scaled Deep Dose Equivalent (DDE). The DDE is numerically equal to the TEDE when there is no Committed Effective Dose Equivalent component.

Table I
Vital Radiological Access Area Dose Summary

Location		Function	Dose	
			CLTP	CPPU (rem TEDE)
1	Control Room	Remote control of all core cooling and auxiliary equipment (30 day dose)	0.11 rem (wb)† 28.5 rem (thyroid)	3.4
2	Technical Support Center	Provide assistance to control room (30 day dose)	4.7 (wb) 15.0 (thyroid)	3.5
3	Post-Accident Sample Sink	Obtain samples for core damage estimations (up to 8 hrs post LOCA) Mission time of 105 minutes per sample collected	1.0 rem (wb) Per sample	1.2
4	Sample Analysis Area	Analyze samples for core damage information (after 1 hr) Mission time of 60 minutes per sample analyzed	0.1 (wb) Per sample	0.12
5	Security Center Off Control Room (SAS)	Security related activities SAS -30 days CAS -4 hours	0.11 rem (wb) 28.5 rem (thyroid)	3.4
6	Security Center Main Guard House (CAS)		2.8 (wb)	3.4
7	Radioactive Waste Control Panel	Secure RB sump pumps at Rad Waste control panel at one (1) hour (2 minute mission time) [(a)]; and provide fuel pool make-up water at 4 days (Mission time about 1 hour) [(b)].	0.17 rem [(a)] (wb) 0.24 rem [(b)] (wb)	0.20[(a)] 0.29[(b)]
8	Hallway from TB to Rad Waste Control Panel Room	Operate shutdown cooling valves. Take containment air samples. Assumed the same as 7(a) above.	See 7(a)	See 7(a)
9	Diesel Oil Storage Tank	Refill tank seven (7) days post LOCA (Mission time of 0.5 hr)	0.025 rem (wb)	0.030 rem
10	Turbine Building Ground Floor	Close railroad car door if open. after one (1) hour (few minutes)	< 2 rem (wb)	< 2.4
11	East Wall RB Exterior	Manual Nitrogen CAD Hook-up after eight (8) hours. One (1) hour duration assumed.	2.4 (wb)	2.9

† wb = whole body

IEPB-B 4

Section 8.4.2, "Activated Corrosion Products and Fission Products" of Attachment 6 to the submittal dated September 10, 2003, states that there may be an increase in the activated corrosion product production, but does not quantify the expected increase in dose rates from the increase in activated corrosion products. Provide the following information: 1) verify that there is an expected increase in activated wear products as well as corrosion products; 2) what plant areas will be affected by the increase in production, transport and deposition of activated corrosion and wear products (i.e., areas where activated corrosion and wear products in systems are the major dose contributor); 3) what are the expected magnitudes of the dose rate increases associated with this impact; 4) provide the technical basis for the expected increase; and 5) what affects this will have on occupancy levels in the affected areas.

Response:

1) Since the feedwater system would need to operate at higher flow rates at higher power levels, some additional wear on friction bearing components is anticipated. However, the basis of the statement is based on ANS 18.1-1999 formulation was used to estimate any such changes and no in-situ measurements have been taken. ANS 18.1-1999 formulation is an equilibrium analysis for concentration which is proportional to power, inversely proportional to total water mass, and to a lesser extent inversely proportional to steam flow.

2) Since the primary source is the feedwater pumps, only components downstream of these pumps and the reactor water cleanup filters would potentially see any increase.

3) In actuality, the magnitude is expected to be negligible, and no observation of any real increase in such products is expected.

4) There is no specific evaluation for wear and corrosion. ANS 18.1-1999 formulation was used to estimate any such changes.

5) There are no practical effects on the occupancy levels in the affected areas.

IEPB-B 5

In Section 8.5, "Radiation Levels", of Attachment 6 to the submittal dated September 10, 2003, the statement is made that the original designs for most plants are sufficiently conservative to compensate for increasing radiation levels from power increases. It goes on to state that "the normal operating radiation levels specified for CLTP conditions were evaluated to increase in proportion to the increase in thermal power." This linear proportionality assumption may be valid for areas where the major source of radiation is the reactor core. However, this is not the case for much of the auxiliary buildings and balance of plant spaces. As noted in question 1 above, N-16 radiation at the turbine increases exponentially with decreased decay time, not linearly with the power increase. The higher rate of steam flow also reduces the hold-up time of the condensate in the condenser hot-well. Therefore, there should be increased N-16 in the condensate bearing systems from both a higher rate of input to the condenser and a reduced decay time. Provide the calculated increase in dose rates around the condensate system. Verify that the expected increase does not create new radiation, or high radiation, areas. Verify that the current plant shielding has sufficient design margin, and that the power increase will not affect the plant radiation zoning.

Response:

The CPPU assessment determining the adequacy of current normal operation plant shielding and radiation zoning is summarized below.

A. The following radiation sources and the associated dose rates are expected to increase approximately linearly with the core power increase:

[[

-]]:

Note : [[

]].

Nitrogen-16 is generated by the (n, p) reaction on O-16 of the reactor water in the reactor core region. [[

]]

[[

]].

B. The following radiation sources and the associated dose rates do not increase linearly with the core power increase:

[[

•

]]

C. The adequacy of the current shielding design and the conclusion that the power increase will not impact the plant normal operation radiation zoning are explained as follows:

- The radiation source terms used in the original plant shielding design were documented in a GE design specification for shielding design and access control and revisited during the CPPU review. These source terms included the reactor water and steam fission product concentrations (μCi/g), the reactor water and steam corrosion product concentrations (μCi/g), the steam N-16 gamma energy emission rate (MeV/g-sec) & steam N-16 concentration (μCi/g), and the noble gas release rates, @ t = 0 and 30 minutes decay time (μCi/sec). The expected radiation source terms in the reactor water and reactor steam at the CPPU power level were also established by GE for the uprate.

A comparison of the gross activity used in the original shielding design and the expected gross activity at CPPU power level shows that the source terms used in the original shielding design are conservative by the following factors:

- Noble gas gross activity (t=30 min) – Original design source/ CPPU expected source = 1.76

- Reactor water halogen gross activity – Original design source/ CPPU expected source = 12

- Reactor steam halogen gross activity – Original design source/ CPPU expected source = 9.0

- Reactor water other Fission Product / Corrosion Product gross activity–Original design source/ CPPU expected source = 6.4

- Reactor steam other Fission Product / Corrosion Product gross activity–Original design source/ CPPU expected source = 6.4

The N-16 concentration in reactor steam for the original shielding design is [[ ]]. The nominal steam N-16 concentration of a pre-uprate BWR is 50 μCi/g (ANS 18.1, 1999). [[

]] The overall CPPU increase factor for N-16 skyshine source in the Turbine Building is 1.26, and that in the offgas system is [[ ]]. Those CPPU increase factors are bounded by the conservative margin of [[ ]] provided by the original design [[ ]]

- A comparison of the reactor water gamma source energy spectra used in the original plant shielding design and that expected at CPPU power level shows that the original design value is conservative by a factor of 5 to 10. Comparisons of the reactor steam gamma source energy spectra used in the original plant shielding design and that expected at the CPPU power level shows that the original GE design basis continues to be bounding at the CPPU power level.

Based on the above radiation source term comparisons, it is concluded that the existing plant shielding has sufficient margin and that the current plant radiation zoning will not be affected by the CPPU.

IEPB-B 6

With respect to the 2nd sentence on page 8-5 of Attachment 4 to the submittal dated September 10, 2003, provide the specific locations of these areas where higher dose rates are predicted, give the reasons for the expected additional increase in radiation levels in these areas, state the percentage increase in dose rates expected, and state what measures will be put in place in these areas to ensure that dose to plant personnel is maintained ALARA.

Response:

With respect to the 2nd sentence on page 8-5 of Attachment 4 that states that the radiation levels in some areas increase by percentages higher than the CPPU, a detailed discussion of the locations where this type of increase is predicted, and the reasons for the expected additional increase is provided in response to NRC RAI Question No. IEPB-B5.

As noted in Section 8-5, and explained in response to NRC Question No. IEPB-B5, CPPU is not expected to change the normal operation radiation zones designations in the plant. Regardless, individual worker exposures can be maintained within acceptable limits by controlling access to radiation areas in conjunction with procedural controls and the site ALARA Program.

Radiation surveys of selected areas will be conducted as part of the power ascension test plan. Refer to page 6 of Attachment 3 to the submittal dated September 10, 2003.

IEPB-B 7

In Section 8.2, "Gaseous Waste Management," of Attachment 6 to the submittal dated September 10, 2003, you state that, "the radiological release rate is administratively controlled to remain within existing limits, and is a function of fuel cladding performance,..." and several other factors. Aside from limiting power (to the point of shutting down the plant, assuming gross fuel leakers, etc.), how can an operator administratively control gaseous effluents from the main condenser offgas during plant operation?

Response:

Aside from power reduction or shutdown to maintain off-gas radiological release rate below limits, reducing main condenser air in-leakage (increasing charcoal adsorber holdup time) and local power suppression (inserting control rods near fuel leaker) are available options. In addition, decreasing adsorber temperature (increasing dynamic adsorption coefficients and holdup times) can be effective in dealing with slow increases in off-gas release rate.

Vermont Yankee (VY) has Technical Specifications requirements and administrative controls to limit fission gas releases to the environment. Plant procedures for reducing power, identifying and suppressing power near leaking fuel and repairing condenser air in leakage exist and have been used at VY to maintain the off gas limits. These procedures are not affected by CPPU.

IROB-B 1

With regard to operator responses, as described in Section 10.6 of Attachment 6 to the submittal dated September 10, 2003, the submittal includes a new task to be incorporated into plant procedures. This task is described as "closing, from the Control Room, a normally open torus vent" in response to "a fire in the reactor building Appendix R event." Please describe the manual actions required to accomplish this task, including the indications required to recognize that the actions are necessary, the procedural steps involved in the actions, the time available for taking the actions, and the indications of successful completion.

Response:

Upon indication of a fire in the Reactor Building, the control room operators will enter Vermont Yankee Nuclear Power Station (VYNPS) procedure OP 3020 "Fire Emergency Response Procedure" (See enclosed excerpts from this procedure). Indications of a fire are:

1) An audible or visual signal from a flame, smoke, or thermal detector.
2) A local fire suppression system activation.
3) The unexpected receipt of an alarm in the Control Room on any of the following annunciators or panel:
   a. Control Room Pyrotronics Panel
   b. "Diesel Fire Pump Running"
   c. "Electric Fire Pump Running"

4) A fire has been reported to the Control Room.

OP 3020 contains separate appendices for various fire locations. The procedure directs the operator to enter the appropriate appendix for the given fire location. The appendices for the appropriate reactor building fire zones will be revised to include operator action that will close the torus vent valve. Specifically, the section titled "Operator Actions:" in each appropriate appendix will be revised adding a step that directs the operator, if a scram has been initiated, to manually initiate a Group II and Group III isolation. This task is accomplished by positioning the control switches for the respective group valves to the closed position and verifying closed indication. (The valves may already be closed if an automatic isolation was received coincident with the scram due to reactor vessel water level shrink). The torus vent valve is a Group III valve and its control switch will be taken to the closed position (even if already closed due to an automatic isolation) and will be verified closed via position light indication. All of the Group II and Group III valves' control switch and position indication are located in the control room. VYNPS procedures currently direct the operator to verify isolations following a reactor scram. If a required isolation does not occur, the operator is directed to initiate the isolation.

The above operator actions are straightforward and there is ample time for successful completion. The time available to take this action is ~ 40 minutes from the time of the reactor scram. Following the control room initial response to a reactor scram, there are no competing functions that would unduly distract the operator from taking these actions. Operators are already trained in these actions (initiating and verifying Group isolations following a reactor scram) at the plant simulator.

Indication of successful completion will be closed position indication for the valve on the main control room front panel.

See Attachment 3, Exhibit 3 for excerpts of procedure OP 3020.

IROB-B 2

The submittal states in regard to operator responses, as described in Section 10.6 of Attachment 6 to the submittal dated September 10, 2003, "the time available for some operator actions is reduced by small increments." Please provide both the bases for these reduced allowable action times and demonstration that the most time-limited actions can be accomplished by all operating crews. Additionally, please describe the consequences of failure to meet the stated time limits. In particular, the response should address the following Key Operator Actions from Table 10-5: IABASE, IOPSLMCF, OPMSIVBP, and VROPERROR3.

Response:

The reduced allowable action timings are due to the increase in decay heat of the CPPU. The timing reductions were calculated using the MAAP code; over 60 MAAP cases were performed in support of the Vermont Yankee (VY) CPPU risk assessment.

Reductions in allowable action timings can have an impact on the human error probability calculated for a given post-initiator human action. The VY human error probabilities for post-initiator human actions are calculated using industry standard techniques that include estimation of the crew cognitive response time and the manipulation time for each action.

Interviews with operators and observations of simulator exercises were used in the VY Probabilistic Safety Assessment (PSA) to support determination of the cognitive and manipulation time estimates. The issue regarding can "all operating crews" accomplish the actions in the reduced allowable times is addressed by: 1) the interviews in support of the VY Human Reliability Analysis (HRA); and 2) the probabilistic aspect of the human error probability calculations. With respect to the first point, interviews of multiple cognizant individuals were performed to support the required timing estimates - in most cases these interviews included an SRO, a Trainer, and an EOP Developer. The fact that multiple cognizant individuals were interviewed precludes the possibility that the input would be skewed by a single individual. With respect to the second point, the required response times estimated for each action are input into a human error probability equation as a Median input value with a distribution characterized by a lognormal standard deviation (see EPRI NP-6560-L). The standard deviation value is supplied by EPRI NP-6550-L and is based on an industry study of operator response times to over 100 different human actions. As such, the estimated response times and associated human error probability calculations take into account the issue of different crews. Therefore, the performance of <u>all</u> VY operating crews is considered in and bounded by the VY PSA human error probability calculations.

In none of the post-initiator actions in the VY PSA does the CPPU reduce the allowable action time frame such that the action is now impossible (i.e., Human Error Probability (HEP) = 1.0) for the crew to complete in the available time.

Regarding the "consequences of failure to meet the stated time limits", from a PSA human error probability calculation perspective, as the estimated allowable time frame for a particular action approaches and exceeds the estimated manipulation time + the estimated diagnosis time then the HEP increases toward 1.0.

From an accident sequence perspective, the consequences of the failure of a particular operator action varies and depends upon the accident initiator and the sequence of equipment failures and other operator action failures. The various combinations are numerous and can not be easily or succinctly summarized. However, the four specific actions questioned in the RAI (all of them ATWS scenario actions) are addressed below.

IABASE: This action is "Operator Fails to Inhibit ADS (ATWS)". The timings in question are summarized as follows:

Case	Allowable Time Window (min)	Estimated Cognitive Time (min.)	Estimated Manipulation Time (min.)
Pre-CPPU	6.2	1.0	0.5
CPPU	5.4	1.0	0.5

As can be seen from these timings, the CPPU allowable time window (based on MAAP calculations) is greater than the estimated cognitive + manipulation times (based on interviews with VY Operations and Training personnel). Failure to inhibit ADS during an ATWS scenario is modeled as directly leading to a core damage end state. This approach remains the same for the pre-CPPU and the CPPU.

IOPSLMCF: This action is "Operator Fails to Initiate SLC Given Main Condenser Failed". The timings in question are summarized as follows:

Case	Allowable Time Window (min)	Estimated Cognitive Time (min.)	Estimated Manipulation Time (min.)
Pre-CPPU	6.0	1.7	0.5
CPPU	5.3	1.7	0.5

As can be seen from these timings, the CPPU allowable time window (based on MAAP calculations) is greater than the estimated cognitive + manipulation times (based on interviews with VY Operations and Training personnel). Failure of timely SLC initiation during an ATWS scenario is modeled as directly leading to a core damage end state. This approach remains the same for the pre-CPPU and the CPPU.

OPMSIVBP: This action is "Operator Fails to Bypass MSIV Isolation Interlocks (ATWS)". The timings in question are summarized as follows:

Case	Allowable Time Window (min)	Estimated Cognitive Time (min.)	Estimated Manipulation Time (min.)
Pre-CPPU	4.0	1.0	0.5
CPPU	3.4	1.0	0.5

As can be seen from these timings, the CPPU allowable time window (based on MAAP calculations) is greater than the estimated cognitive + manipulation times (based on interviews with VY Operations and Training personnel). Bypass of the MSIV isolation interlocks is part of the main condenser recovery process. Failure to bypass the MSIV isolation interlocks directly leads to main condenser recovery failure, but does not directly lead to a core damage end state. Initiation of RHR or containment venting are alternative actions that are still viable to fulfill the containment heat removal function. This approach remains the same for the pre-CPPU and the CPPU.

VROPERROR3: This action is "Operator Fails to Align RHRSW Injection to RPV (ATWS)". The timings in question are summarized as follows:

Case	Allowable Time Window (min)	Estimated Cognitive Time (min.)	Estimated Manipulation Time (min.)
Pre-CPPU	15.0	8.2	1.0
CPPU	11.6	8.2	1.0

As can be seen from these timings, the CPPU allowable time window (based on MAAP calculations) is greater than the estimated cognitive + manipulation times (based on interviews with VY Operations and Training personnel). Failure to align RHRSW injection for level control during an ATWS scenario does not directly lead to a core damage end state, other injection systems must also fail. This approach remains the same for the pre-CPPU and the CPPU.

RLEP-C 1

Due to the EPU, there will be an increase in current across the transmission lines. Discuss the electric shock hazards associated with the increased current. Were the transmission lines designed and constructed in accordance with the applicable shock prevention provisions of the National Electric Safety Code?

Response:

There will be an increase in current across transmission lines due to the Vermont Yankee (VY) power uprate, but there will be no change in electric shock hazard. Transmission line rated voltage will remain unchanged, and therefore required transmission line clearances remain unchanged. A power uprate System Impact Study (SIS) which included load flow analysis has been completed. The study establishes that under transmission system "stressed" conditions, CPPU line loadings remain within current ratings. The line ratings contained within the system model consider transmission line sag due to loading (current, wind, ice, and ambient temperature). The additional loading due to CPPU does not decrease the required clearances established by the utilities which operate the lines because the lines operate within their ratings. In general the clearances for transmission lines are based on the National Electric Safety Code (NESC); however, individual utilities may be required to meet specific local or state requirements which may be stricter than clearances established by the NESC.

RLEP-C 2

What is the expected increase in water temperature at the discharge point due to the EPU? Approximately how far from the discharge will this temperature gradient spread out - will it dissipate immediately due to the mixing in the Connecticut River?

Response:

The quantity of heat discharged to the Connecticut River for a given river flow and upstream river temperature is limited by the National Pollutant Discharge Elimination System (NPDES) Permit and will not change with CPPU. The change in the temperature of the water at the point of discharge may vary somewhat from existing conditions; however, since the amount of heat discharged for a certain river condition is the same as pre-uprate, the discharge will mix with the river as described below.

The temperature of the water exiting the discharge structure will immediately begin to cool as it mixes with the Connecticut River. A joint hydrological-biological study of the Vernon Pond conducted between 1974 and 1977 (Binkerd et al., 1978), included a thermal survey of Vernon Pond using both a long-term deployment of in situ temperature probes and a series of short-term surveys using a towed temperature probe. The towed device was used to determine temperatures at a given depth along a series of across-channel transects. In addition, the towed probe was used to obtain profiles of temperature with depth at fixed locations around the Vernon Pond. The study concluded that discharge of cooling water from Vermont Yankee resulted in two distinct flow patterns within Vernon Pond. During periods of relatively high river flow, the strong river currents shear the plume as it emerges from the Station's discharge and is deflected to flow along the Vermont shore. In contrast, during periods of low river flow, the plume extends out into the river channel before being swept downstream. In both of these flow regimes, warm plumes were found to sink if the ambient water temperature in the river was less than 4°C (39.2°F), the temperature at which water attains its maximum density. During other times, the heated discharge exists as a surface plume.

RLEP-C 3

Is there any critical habitat in the vicinity of the river discharge? What organisms are in the vicinity of the discharge and how will they be affected?

Response:

No critical habitat exists in the vicinity of the Vermont Yankee discharge.

There are approximately 25-30 species of fish that are routinely collected in the vicinity of the Vermont Yankee Power Station as part of the NPDES-required fisheries monitoring program. These monitoring programs have been ongoing since the early 70's and the diversity of the species is essentially the same, except that more Atlantic salmon and American shad are present today as a result of the construction of fish ladders and the intensive restoration effort for these two species.

Similarly, the macroinvertebrate community is monitored each year as a requirement of the NPDES Permit. During 2002, a special study of the macroinvertebrate community in lower Vernon Pools was conducted. The objective of the study was to evaluate the distribution of macro-invertebrates within, and adjacent to, the Vermont Yankee thermal discharge during the open water period of 2002. Artificial multiplate samplers and continuously recording water temperature data loggers were deployed in redundant pairs among two upstream control and nine exposed stations in lower Vernon Pool in July, August, and October. A total of 33 pairs of multiplate samples were obtained and one sample from each pair was randomly selected and analyzed for macroinvertebrate community composition and abundance during 2002. The resulting community metrics were compared with the corresponding water temperature data to test for significant negative relationships with increased exposure to the Vermont Yankee thermal discharge.

Typical seasonal trends in surface water temperature and in the macroinvertebrate community metrics were observed in lower Vernon Pool during the study. Surface water temperatures in lower Vernon Pool were warm during July, highest during August, and cooled significantly during the last half of October 2002. However, differences among all stations between the highest and lowest average surface water temperatures were only 1.6°C, 1.0°C, and 1.1°C, respectively (Normandeau Associates 2002). The upstream control stations exhibited lower average surface temperatures during the July and August 2002 incubation period compared to the stations exposed to the heated discharge. October 2002 average surface water temperatures were relatively homogeneous throughout the study area, most likely due to the fact that the Station was in a refueling outage during much of the sampling period.

A total of 7,221 macroinvertebrates representing 88 taxa were enumerated from the multiplate samples. The total abundance of macroinvertebrates declined among the three sampling periods from 3352 in July to 2353 in August, and to 1516 in October. Taxa richness, diversity, and Hilsenhoff biotic index values also declined in a temporal pattern similar to abundance. The decline in these macroinvertebrate community metrics reflects the natural seasonal cycle of a peak in abundance occurring during the mid-summer period, followed by organisms that have completed their annual life cycle depositing eggs and dying, or developing into a diapause state for survival during colder winter months.

A significant ($p<0.05$) negative relationship was observed between control and exposed sampling stations in lower Vernon Pool for only one of the macroinvertebrate community metrics examined (diversity); however the control stations exhibited lower diversity than the stations exposed to the thermal plume.

Examining the macroinvertebrate community metrics along an east to west gradient among the nine stations exposed to the thermal plume revealed that exposed stations closest to the Vermont shore exhibited higher diversity and Diptera richness than those stations near the New Hampshire shore opposite from the Vermont Yankee generating station. Therefore, Normandeau Associates concluded that the artificial multiplate sampling conducted in lower Vernon Pool during 2002 revealed no significant negative macroinvertebrate community response to exposure to the Vermont Yankee thermal discharge. In fact, a more diverse and robust macroinvertebrate community was found to colonize the artificial samplers in the thermal plume at stations nearest to the Station's discharge.

Since the quantity of heat discharged to the Connecticut River for a given river flow and upstream river temperature will not change with CPPU, there should be no effects of CPPU on the fish population and the macroinvertebrate community.

RLEP-C 4

Are there any aquatic species that could be caught in the intake structure? Are any of these Federally or State listed? Does Entergy have any protective measures to prevent aquatic species from entering the intake area?

Response:

Vermont Yankee (VY) can and does entrain and impinge aquatic species. Entrainment of fish eggs and larvae was monitored for over a decade beginning in 1972. Entrainment was determined to be insignificant by Vermont Yankee's Environmental Advisory Committee (EAC) and was dropped from the required monitoring program. The EAC is comprised of representatives from Vermont Department of Environmental Conservation, Vermont Department of Fish and Wildlife, New Hampshire Fish and Game Department, New Hampshire Department of Environmental Services, Massachusetts Office of Watershed Management, Massachusetts Division of Fisheries and Wildlife, and the Coordinator of the Connecticut River Anadromous Fish restoration program of the U.S. Fish and Wildlife Service.

Fish impingement has been monitored annually since 1972, and is considered low. There is a spring and fall period of monitoring. In both seasons, weekly and 24 hour samples are collected. All fish are identified, weighed, measured, and enumerated. This data is summarized and reported in Vermont Yankee's annual reports entitled "Ecological Studies of the Connecticut River, Vernon, Vermont." The EAC has established impingement limits for both American shad and Atlantic salmon. Vermont Yankee has never approached the impingement limits for these species.

VY operates subject to and with the benefit of a NPDES Permit, No. 3-1199 (the "Permit"), reissued by Vermont Agency of Natural Resources ("ANR") most recently in June 2003, which includes various protective measures designed to ensure that Station operations meet applicable federal and state law, including 316(b) of the Clean Water Act, as ANR necessarily concluded in its last renewal determination.

Relative to impingement, the Permit requires that comprehensive impingement sampling be conducted when the Station cooling water intake is operating in open/hybrid cycle according to a spring and fall schedule, as outlined in the Permit. Consistent with this sampling protocol, the Permit establishes daily and annual impingement limits for two species, American shad and Atlantic salmon. The Station has never approached the established daily or annual limits for these species, and ANR necessarily has concluded that impingement of other species by Station operations meets applicable law.

Relative to entrainment, historical studies, conducted between the early 1970's through the mid 1980's at Vermont Yankee, indicated such low entrainment numbers that ANR concluded no further entrainment sampling was required. Consequently, ANR concluded that entrainment sampling should be replaced with alternative biological monitoring of in-River species.

To that end, for approximately two decades, VY has continued to conduct extensive monitoring designed to identify any potential impacts to aquatic species in the area reasonably able to be affected by Station operations. The biological monitoring has changed from time to time, as directed by ANR. The biological monitoring currently required in the Permit includes macroinvertebrates, larval fish, resident and anadromous fishes, as well as objective specific studies as deemed necessary or useful by the ANR and Vermont Yankee's Environmental Advisory Committee ("EAC") for the Station. These studies have demonstrated that Station operations have had no adverse impacts on aquatic species.

See Attachment 3, Exhibit 4 "Ecological Studies of the Connecticut River Vernon, Vermont Report 32 May 2003"

RLEP-C 5

How many full time employees and contractors work at VYNPS? Will the EPU affect the size of the labor force? Will the EPU have an affect on the labor force required for future outages? How many additional people are required for current outages?

Response:

The number of full time employees and contractors at VYNPS is approximately 670.

The site workforce is not expected to change as a result of CPPU with the exception of the workforce during the 2004 refueling outage.

During the 2004 refueling outage, scheduled for the spring of 2004, up to 500 additional craft workers and supervisors will be hired to install the modifications required for CPPU. Since most of the CPPU modifications are planned for the spring 2004 outage, the workforce for future outages should not be affected by CPPU.

The number of additional personnel required for refueling outages is normally less than 700. As stated above, the modifications required for CPPU will increase the number of additional craft workers and supervisors by up to 500 during the spring 2004 refueling outage.

RLEP-C 6

Is Entergy a major employer in the community? Is Entergy a major contributor to the local tax base? What affect will the EPU have on the local tax base?

Response:

Entergy is a major employer in the community and a major contributor to the local tax base.

Vermont Yankee's public school taxes are assessed and collected by the State of Vermont under special statute. Vermont Yankee is assessed at the state level, and the plant is exempted from the local traditional property tax levy. The State Education Tax is based on a tax rate schedule applied to levels of generation over a three-year average. Additional generation of electricity from EPU will result in proportional tax increases. (32 V.S.A. § 5402a)

Entergy's contribution to the remaining local tax base is governed through the year 2010 by a Tax Stabilization Contract that was entered into by the Town of Vernon and the owners of Vermont Yankee on June 7, 2000. The contract was properly assigned to Entergy as the new owner.

The contract sets forth the Total Listed Value to be utilized for each year through 2010 for purposes of assessment of Municipal Services property tax. The contract specifies in Sections 1.01 – 1.03 that this Total Listed Value applies to all real and personal property owned by the facility on April 1, 2000, and all real and personal property thereafter acquired, which is used in connection with the generation of electrical power through the nuclear fission process.

RLEP-C 7

What is the volume of solid and liquid low-level radioactive waste (LLW) currently generated (in calendar year 2002) at VYNPS? What is the average annual amount of solid and liquid LLW generated at VYNPS?

Response:

The Low Level Waste generated at Vermont Yankee is in the form of resins and sludges extracted from a liquid base or dry compressible waste and contaminated equipment. The only waste increases expected for CPPU are for Reactor Water Cleanup and Condensate Demineralizer resins because of increased flows associated with the steam, feedwater and condensate systems. CPPU will result in a 17.8 % increase in solid waste, with a baseline value of 1291 ft3 and a subsequent increase of 230 ft for a total expected of 1521 ft3. The amount used in the analysis for CPPU conditions are based on 2001 since it represented a year of peak usage based on review of annual waste generation amounts. Vermont Yankee does not discharge liquid waste; however, the estimated increase in liquid waste is 109,556 gallons used a baseline value from 2001 of 9,491,000 gallons.

The average amount of solid waste generated at Vermont Yankee is 1361 ft 3 of solid waste including resins. sludge and compacted waste. This value is based on years 2000 through 2002 which includes refueling outage years. In 2002, VY generated a total of 898.4 ft3 of solid waste after volume reduction.

RLEP-C 8

Due to the EPU, what is the increase in on-site occupational dose? What will be done to limit the increase?

Response:

Normal operation radiation levels in the plant will increase by approximately the percentage increase in power level, i.e; 20%. Some areas will reflect an additional small increase due to higher steam flow. The increased steam flow rate and velocity due to CPPU will result in shorter travel times to the turbine, and less radioactive decay in transit, leading to higher radiation levels in and around the turbine, and an estimated overall CPPU increase factor of 26 %. During plant shutdown, radiation levels in most areas of the plant will increase by no more than the percentage increase in power level. In a few areas near radwaste equipment, the increase could be slightly higher.

Individual worker exposure is maintained within acceptable limits by the site ALARA program, which controls access to radiation areas. Procedural controls compensate for increased radiation levels to ensure that worker exposure remains ALARA, and that the normal operation radiation zones are labeled and controlled for access in accordance with the requirements of 10CFR20 related to allowable worker exposure and access control.

RLEP-C 9

Discuss the effect of skyshine on direct radiation doses offsite. How is whole body dose monitored at VYNPS? What is the highest annual offsite dose due to skyshine? How will the EPU affect dose due to skyshine? How will dose due to skyshine be monitored?

Response:

Based on radiation measurements, the west side boundary has been established as the recipient of the highest direct radiation dose offsite. At this location, the major direct radiation sources are: (1) the N-16 source in the Turbine Building, (2) radwaste stored in the North Warehouse, (3) radwaste on the Low Level Waste (LLW) Storage Pad, and (4) old turbine rotors and casings. Among those four radiation sources, the N-16 source in the Turbine Building is the major dose contributor (approximately 90%, see response to IEPB-B NRC RAI Question No.1).

The energy spectrum and direction of radiation from the Turbine Building N-16 source were measured in 2001 with high purity germanium (HPGe) detectors. The directions of the radiation (direct radiation from the turbine building components or scattered radiation from the sky) were measured by placing directional shielding around the HPGe detectors; e.g., unshielded HPGe detectors aimed towards the high pressure turbine to establish the contribution of direct line of site radiation vs. shielded HPGe detectors aimed skyward to establish the skyshine radiation field). The contribution from terrestrial and cosmic radiation were also addressed. The incident fluence spectra were evaluated to yield the physical characteristics of the radiation and were converted to exposure rate and dose rate contributions. Results of the HPGe measurements indicated that the principal source of the radiation dose at the west side boundary is attributed to skyshine radiation, with the direct shine contribution being less than 2.5% of the total radiation.

The radiation dose from the waste on the LLW Storage Pad also has a skyshine component. However, the combined radiation dose at the west side boundary from this source (direct line-of-sight component plus skyshine component) is only about 1% or less of the total direct dose from all sources. (see response to IEPB-B NRC RAI Question No.1)

Based on the above discussion that indicates that the dose contribution at the fence line due to direct shine from turbine building sources is minimal, and taking into consideration the response to IEPB-B NRC RAI Question No.1, it is concluded, that the highest annual dose at the west side boundary of 13.4 mrem (at CLTP) from the N-16 source in the Turbine Building is primarily due to skyshine. The CPPU is expected to increase the N-16 source in the Turbine Building by approximately 26%. Consequently, the maximum CPPU site boundary dose due to N-16 sources in the Turbine building can also be attributed, primarily to skyshine, and is projected to be 16.9 mrem (see response to IEPB-B NRC RAI Question No.1 for detail on dose estimate).

VYNPS monitors and controls radioactive releases and doses in accordance with Technical Specification 6.7.D Radioactive Effluent Controls Program. The details of the program are described in the Offsite Dose Calculation Manual (ODCM). Whole body dose calculation methods are described in the ODCM. The portion of the dose that is due to skyshine is implicit in the method and is based on the test measurements described above.

RLEP-C 10

What is the uranium-235 enrichment value (weight percent of uranium-235) for fuel used for the EPU? What is the expected fuel burnup (in megawatt days per metric ton of uranium (MWd/MTU)) for the EPU?

Response:

The CPPU analysis assumed a conservative maximum bundle enrichment of 4.6 w/o U-235. In Cycle 24, beginning in 2004, the maximum bundle enrichment is 4.2 w/o U-235.

The expected core average exposure for the CPPU is 35,000 MWd/MTU (Megawatt days per metric ton of uranium) and the maximum bundle exposure is 58,000 MWD/MTU.

SPLB-B 1

In NRC RS-001, Revision 0, "Review Standard for Extended Power Uprates," Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's application should confirm that these elements are not impacted by the extended power uprate ..." The reviewer notes that Section 6.7, "Fire Protection," of Attachment 6 to the submittal dated September 10, 2003, addresses only items (2) through (5) above. At a minimum, please provide a statement to address item (1), no effect upon "administrative controls," and a statement confirming no "increase in the potential for a radiological release resulting from a fire."

Response:

Administrative controls in the Technical Specifications, the Technical Requirements Manual, and the Vermont Yankee Operational Quality Assurance Manual were reviewed and there are no changes required for CPPU.

Furthermore, as indicated by Table 6-5, Appendix R Event Evaluation Results, in Attachment 6 to the September 6, 2003 submittal, all of the Appendix R acceptance criteria were met, therefore there is no increase in the potential for a radiological release resulting from a fire.

SPLB-B 2

In RS-001, Revision 0, Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "... where licensees rely on less than full capability systems for fire events ..., the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe shutdown procedures." The reviewer notes that Section 6.7, "Fire Protection," of Attachment 6 to the submittal dated September 10, 2003, addresses all but the following item above - "no adverse consequences on the <u>reactor pressure vessel</u> integrity or the attached piping" (the Application does address the effect on <u>containment</u> pressure and temperature). At a minimum, please provide a statement to address this item.

Response:

There are no fire scenarios that degrade automatic overpressure protection (i.e. the ability of the safety/relief valves and safety valves to perform their pressure relief function), and CPPU does not affect this overall conclusion, therefore there are no adverse consequences on the reactor pressure vessel integrity or the attached piping.

SPLB-B 3

Section 6.7.1, "10 CFR 50 Appendix R Fire Event," of Attachment 6 to the submittal dated September 10, 2003, discusses an evaluation performed to demonstrate safe shutdown capability in compliance with the requirements of 10 CFR 50 Appendix R assuming CPPU conditions. The submittal states that the results of the Appendix R evaluation for CPPU provided in Table 6-5 demonstrate that fuel cladding integrity and containment integrity are maintained and that sufficient time is available for the operator to perform the necessary actions." Upon reviewing Table 6-5 ("VYNPS Appendix R Fire Event Evaluation Results"), the reviewer was able to find references to only two of the values provided, namely the drywell design pressure of 56 psig and the containment structure design limit of 281°F for suppression pool bulk temperature, both from Table 4-1. The reviewer was also able to confirm Notes 5, "NPSH demonstrated adequate" (Section 4.2), and 6, "Overpressure credit required" (Section 4.2.6). Please provide references, including appropriate extracts from the UFSAR, Appendix R evaluation, etc., for all remaining notes and values in Table 6-5.

Response:

The following provides additional details regarding Table 6-5. The Vermont Yankee Safe Shutdown Capability Analysis is incorporated by reference in UFSAR Section 10.11.3.

<u>Time to Core Uncovery (TCU)</u>

The following information is extracted from the Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, page 27.

> This analysis determines the time operators have available to initiate RCIC from the alternate shutdown stations. The timing for the scenario begins when the operator scrams the reactor and isolates the MSIVs in the Control Room. These are immediate actions once the shift supervisor makes the decision to execute the alternate shutdown procedure.......Core uncovery (marked by onset of core heatup) will begin at approximately 25.3 minutes.

This analysis was redone at CPPU conditions and is documented in Vermont Yankee calculation VYC-2270, Rev. 0, page 274. The TCU at CPPU conditions is documented as 21.33 minutes, which was rounded to 21.3 minutes in Table 6-5.

<u>Cladding Heatup (PCT)</u>

The following information is extracted from the Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, page 28.

> This analysis was performed to show that ADS/LPCI can be used as a backup for RCIC for fires which require control room evacuation. The results show that when the

> operators follow OP 3126 and defer reactor blowdown until LPCI is available at 25 minutes, and only 2 SRVs are available due to worst case fire damage, only minor core heatup for a short duration occurs. The peak clad temperature is below 1300°F, which is well below the level where clad damage would occur.

The actual value of 1292.9 °F documented in Table 6-5 is from Vermont Yankee calculation VYC-1917, Rev. 0, page 476.

This calculation was redone for CPPU and is documented in VYC-2270, Rev. 0, page 274. The resulting PCT is 1475.4 °F.

The acceptance criterion of 1500°F is documented on page 6, letter dated 8/12/97 "Technical Evaluation of VYNPC Requests for Exemption from 10CFR50 Appendix R, Section III.G and III.L, (TAC Nos. M95442 and M95149)" Rev. 2, BNL, attached to USNRC Letter to VYNPC, NVY 97-128.

Peak Drywell Pressure

The following information is extracted from the Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, page 28.

> To address the consequences of loss of drywell cooling during a fire, a containment heatup analysis was performed and operational strategies developed. Significant containment heatup could occur if containment coolers are unavailable. To mitigate the challenge to both containment integrity and electrical equipment operability, a timely cooldown to cold shutdown strategy was developed. For alternate shutdown, drywell sprays are manually initiated if necessary. For fire scenarios where the operator remains in the Control Room, the EOPs are followed and will govern when drywell sprays are utilized. Timely cooldown is initiated for all Appendix R fire scenarios where drywell cooling is impacted.

At CLTP, the peak drywell pressure for the limiting scenario is 23.6 psig [Vermont Yankee calculation VYC-1457, Rev. 1].

The calculation supporting this result was examined and it was determined that the only effect that CPPU would have on the results would be due to the increase in feedwater temperature. The increase in feedwater temperature increases the sensible heat load in the drywell by 0.6%. This increase in sensible heat load would result in no more than a 1 °F increase in drywell temperature, and this increase would have an insignificant impact on the calculated peak drywell pressure of 23.6 psig [Vermont Yankee technical evaluation TE 2003-065, page 2].

The drywell design pressure is 56 psig [UFSAR Section 5.2.3.2]. However, an acceptance criterion of 25 psig is used based on RCIC operational limits [Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, Reference 7.8.20].

Suppression Pool Bulk Temperature

The following information is extracted from the Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, page 28.

> Bounding analyses have been performed to envelope the full range of possible cooldown scenarios. These include normal cooldown, ADS blowdown, and alternate shutdown cooling scenarios.

At CLTP, the maximum bulk suppression pool temperature is 180.9 °F[Vermont Yankee calculation VYC-2120, Rev. 0]. The same scenario for CPPU resulted in a maximum temperature of 189.5 °F [Vermont Yankee calculation VYC-2306, Rev. 0]. This peak temperature is below both the structural design temperature of 281 °F [UFSAR Section 5.2.3.3] and the torus attached piping limit of 195 °F [Attachment 6, Section 3.5.2], therefore the results are acceptable for CPPU.

The effect of pool temperature on NPSH is discussed below.

Net Positive Suction Head

The following information is extracted from the Vermont Yankee Safe Shutdown Capability Analysis, Rev. 6, page 28.

> The results indicate that torus temperature NPSH limits will not be exceeded.

Calculations of suppression pool temperature (see above) at CLTP show that temperatures are within LOCA peak of 182.6 °F [UFSAR Section 14.6.3.3.2]. NPSH calculations at the CLTP LOCA peak temperature show acceptable NPSH margins [Vermont Yankee calculation VYC-0808, Rev. 6].

The increased decay heat associated with CPPU will cause suppression pool temperatures for limiting scenarios to increase to the point where some credit for containment overpressure is required to assure adequate NPSH. In all cases, the required overpressure is less than the available overpressure [Vermont Yankee calculation VYC-2314, Rev. 0].

SPSB 1

Attachment 6, Section 10.5, of the submittal dated September 10, 2003, states that the core-damage frequency (CDF) will increase from 7.77E-06/y to 8.10E-06/y as a result of the EPU. Section 10.5.7 states that the probabilistic safety assessment (PSA) model used for the analysis is VY02 Revision 6, which was completed in July 2003. In May 2003, the NRC conducted a benchmarking exercise of its Significant Determination Process (SDP) Phase 2 model by comparing its results to the licensee's PSA model. During the benchmarking exercise, the VYNPS PSA model was identified as Revision 3 (4/30/03), with a CDF due to internal initiators and internal floods of 4.89E-06/y.
Please explain what changes were made to the VYNPS PSA model and why the CDF apparently increased during the May-July 2003 time frame.

Response:

In VY02 Revision 4, June 2003, the Vermont Yankee Nuclear Power Station (VYNPS) Probabilistic Safety Assessment (PSA) model was modified (unrelated to CPPU) with the elimination of Control Rod Drive (CRD) injection as a system capable of providing adequate core cooling early in the event sequence when high decay heat rates exist. This change accounts for the increase in core-damage frequency. Note that CRD is still credited as a potential 'late' alternate injection source when early injection has been successfully accomplished by the LPCI, core spray or condensate systems.

See the table below for VY02 revision history during the May – June 2003 time frame:

VY02 Revision	Description of Change(s)	CDF
3	Model used during SDP benchmark visit	4.89E-06/y
4	This model incorporated the following two modifications to the base case model based upon discussions during the SDP benchmark: a. Removing CRD as a potential source of injection early in the event sequence. CRD is still credited as a potential 'late' alternate injection source when early injection has been accomplished by LPCI, core spray or condensate systems. b. Expanded use of the diesel driven fire pump (DDFP) as a potential source of alternate injection to include not only the SBO sequences, but also to include non-SBO sequences when random failures or support system failures prevent alternate injection by either the control rod drive (CRD) or condensate transfer systems (CT).	7.81E-06/y
5	No changes made to Level 1 models	7.81E-06/y
6	Corrected errors in quantification of fault trees for top events CG, S1 and S2, and AICD.	7.77E-06/y

SPSB 2

Attachment 6, Section 10.5.7, of the submittal dated September 10, 2003, states that an industry peer review of the PSA was performed in November 2000. Please provide the Category A and B review findings, and explain how and when each finding was resolved.

Response:

A total of 104 PSA certification Findings and Observations (F&O's) were identified. Of these, there was 1 category 'A' and 51 category 'B' review findings. These F&Os are provided in the following table, together with how and when each finding was resolved.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
IE-03	B	Loss of offsite power frequency is based on NUREG-1032, which is dated. More recent data is available from EPRI and from NRC. Also the recovery probabilities in NUREG-1032 have a mysterious basis, which, even if accurate, is not likely to be true so many years later.	In the VY PRA 2002 Update, the loss of offsite power IE frequency was updated with the most relevant data from NUREG/CR-5496 ("Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996").
IE-05	B	The available SCRAM history (~15 yr.) is excellent. However, the frequencies are developed using all 15 years worth of data and assuming the rate is constant over the 15-year period. General U.S. performance would suggest that the number of SCRAMS is smaller in recent years, while the number of plant operating hours is larger. Therefore, a 15-year average may not be representative.	In the VY PRA 2002 Update, the transient IE frequency evaluation was performed with 5-year rolling average. Sensitivity analysis with 10-year time interval proved to be more suitable for final update. This was then used for new updated transient IE frequency.
IE-06	B	IE frequencies are developed using plant-specific experience. However, the details of the calculations have not been recorded. For example, the number of operating hours is presented in the documentation, but missing is how it was derived by adding each year's contribution. The division of the number of SCRAMS by this total is not shown.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. This was resolved by the completion of the IE update documentation for the VY PRA 2002 Update.
IE-07	B	WASH-1400 LOCA frequencies are outdated.	For the VY PRA 2002 Update, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995" (NUREG/CR-5750) was selected as the main source for new LOCA frequency values.
IE-08	B	Vermont Yankee has two RCS safety valves, which vent to the drywell. Spurious opening of such a valve can, behave like a medium LOCA, and such an event has occurred at Dresden Station. At Dresden, the jet from the spurious operation of a misadjusted valve bent the operating handle of another, creating a steam-space LOCA. In the Quad Cities PRA, most of the medium LOCA frequency comes from spurious opening of code safety valves. Vermont Yankee should evaluate this as an initiating event, independently or by combining its frequency with medium LOCA.	The VY PRA 2002 Update selected the "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995" (NUREG/CR-5750) as the main source for new LOCA frequency values. Spurious opening of a code safety or safety-relief valve was specifically addressed in the 2002 update. These events are evaluated using the Medium LOCA event tree.
IE-09	B	Treatment should be refined for certain special initiators. For example, it would be better to quantify a loss-of-instrument-air fault tree rather than simply judging it to be unimportant. Also, including IA in the model makes it practical to better judge its importance in online risk. In another example, Vermont Yankee judges loss of TBCCW to be covered by loss of service water. The plant response to loss of TBCCW may be similar to the response to loss of service water, but the loss of TBCCW frequency should be quantified and added to the loss of service water initiator.	Loss of Instrument Air is not explicitly modeled as a separate initiating event because its failure frequency and impact on the plant (plant damage state) are considered to be bounded by the initiator TFWMS. The frequency of TFWMS is approximately 0.1 per year. It is judged that random failure and non-recovery of all instrument air is on the order of E-02 to E-03 per year. In addition, the plant damage state for failure of Instrument Air is essentially the same as TFWMS. Therefore, it is judged that rigorous evaluation of Instrument Air as a separate initiator will have an insignificant influence the overall PRA results. Loss of TBCCW is not explicitly modeled as a separate initiating event for the same reasons as Instrument Air. The frequency of TFWMS is approximately 0.1 per year. It is judged that random failure and non-recovery of TBCCW is on the order of E-02 per year. In addition, the plant damage state for failure of TBCCW is assumed to cause a TFWMS-type event. Therefore, it is judged that rigorous evaluation of TBCCW as a separate initiator will have an insignificant influence on the overall PRA results.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
IE-10	B	Given its severity, loss of both DC buses should be analyzed. For Quad Cities, this is a significant contributor to CDF, and common cause is a factor.	Dual failure of both DC buses (DC-1 and DC-2) as an initiating event is not explicitly modeled. VY has never experienced this type of initiator nor are we aware of any industry experience for this event. Therefore, it is judged that this event is of extremely low likelihood. Also, sufficient data does not exist to adequately characterize the common cause dependence for dual failure of both DC buses as an initiating event. Conservative treatment of the common cause dependence would incorrectly skew the PRA results. Note that the PRA does, in fact, model common cause between the DC buses when calculating the random failure probability of DC power following a plant trip (demand). This modeling adequately captures the plant damage state of dual DC bus failure. Based on the above, rigorous evaluation of dual loss of DC buses as an initiating event is not performed.
IE-11	B	The frequency of loss of service water is determined by rough and imprecise calculations using industry data. It would be better to develop an initiating event fault tree.	In the VY PRA 2002 Update, the loss-of-service-water initiating event frequency was determined by using a newly developed fault tree.
IE-12	B	Analysts who worked on the Vermont Yankee PRA state that internal independent review of initiating event frequency analysis and calculations was performed. However, there is no written evidence of this independent review. To improve quality and to avoid oversights, independent review is important.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. In the VY PRA 2002 update of the initiating event frequencies, an independent review and signoff was performed.
IE-13	B	Loss of 4160V AC bus 2 should be addressed as a potential special initiator. Its loads include 2 condensate pumps which if lost would most likely perturbate the water level control system to the point of scram. The frequency determination for the Inadvertently Opened Relief Valve (IORV) initiator is calculated in a manner that may not necessarily be conservative.	At VY, 4kV AC Bus 1 and Bus 2 supply the feedwater pumps and condensate pumps. If either Bus 1 or Bus 2 fails, the PRA model assumes loss of feedwater/condensate capability. This is the case for both the TFWMS event (0.1 per yr) and the TLP event (0.04 per yr). The frequency of failure of Bus 1 or Bus 2 is judged to be approximately the same as loss of Bus 3 or Bus 4, on the order of E-03 per year. Therefore, the frequency and plant impact from loss of Bus 1 or Bus 2 is adequately bounded by the TFWMS and TLP initiators and rigorous evaluation of loss of Bus 2 as a separate initiator will have an insignificant influence on the overall PRA results. Based on NUREG/CR-5750 data, and VYNPS specific experience related to the IORV events, double Bayesian update is performed to estimate an updated frequency for IORV.
AS-01	B	The IPE does not include proper references to specific EOPs modeled in the analysis, nor does the documentation explain the equipment success criteria (1 SW pump for some scenarios, 2 pumps for others, for example).	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Proper references to the specific EOPs modeled in the human reliability analysis (HRA) are included in the supporting documentation: (1) "Human Reliability Analysis for Vermont Yankee", by ERIN Engineering and Research, Inc., dated January 1992, and (2) "Vermont Yankee Human Reliability Analysis Update", by ERIN Engineering and Research, Inc., dated June 2000. Equipment success criteria is now clearly defined at the system level (i.e., top event) for each accident sequence type (e.g., ATWS, S-LOCA, etc.). The information is arranged in tabular format in the new notebook: "Thermal-Hydraulic Success Criteria, based on the information contained in letter NFVY-02-001Rev1, "Success Criteria for Vermont Yankee Individual Plant Evaluation", from Duke Engineering & Services, dated January 15, 2002.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
AS-05	B	Success criteria are not clearly defined.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Success criteria is now clearly defined at the system level (i.e., top event) for each accident sequence type (e.g., ATWS, S-LOCA, etc.). The information is arranged in tabular format in the new notebook: "Thermal-Hydraulic Success Criteria, based on the information contained in letter NFVY-02-001Rev1, "Success Criteria for Vermont Yankee Individual Plant Evaluation", from Duke Engineering & Services, dated January 15, 2002.
AS-07	B	References are not provided for success criteria basis calculations.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Equipment success criteria is now clearly defined at the system level (i.e., top event) for each accident sequence type (e.g., ATWS, S-LOCA, etc.), together with reference to the analysis of record which provides the bases for the criteria. The information is arranged in tabular format in the new notebook: "Thermal-Hydraulic Success Criteria, based on the information contained in letter NFVY-02-001Rev1, "Success Criteria for Vermont Yankee Individual Plant Evaluation", from Duke Engineering & Services, dated January 15, 2002.
TH-04	B	MAAP cases are not clearly linked to success criteria for specific conditions. A success criteria matrix would be helpful, and TH items would then be covered.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Success criteria is now clearly defined at the system level (i.e., top event) for each accident sequence type (e.g., ATWS, S-LOCA, etc.). The information is arranged in tabular format in the new notebook: "Thermal-Hydraulic Success Criteria". The limitations and critical assumptions associated with each are contained either in the lead-in discussion for this table, or in the end notes for this table.
SY-04	B	A note has been added for the utility to evaluate whether or not the Power/level Control model as evaluated with MAAP calculations for ATWS conditions (i.e. operator actions timing for success, and so on) matches that used in the plant training simulator.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The Simulator benchmarking calculations do not model the same scenarios as those of MAAP IPE scenarios.
SY-05	B	The service water system has a logic that will isolate non-essential loads if header pressure drops to 50 psig for 27 seconds. There is no evaluation of the status of this logic for SBO where the circuitry is de-energized and later re-energized. This could have a significant impact on SBO sequences.	The current Vermont Yankee PRA model (ref: VY02) assumes the isolation of valves SW-19A/B and SW-20 for Station Blackout Scenarios. In an SBO scenario, turbine building systems would be rendered unavailable due to loss of electric power. Reactor building equipment remaining operable during an LNP event will be successfully cooled by SW/RHRSW with, or without isolation of turbine building loads.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
SY-06	B	Modeled systems tend to leave out details that could be pertinent in system evaluation. This comment applies to undeveloped events that are not well defined. The diesel models do not include sequencing relays. As a result it becomes very difficult to fully understand and validate the model. Grouping these items as opposed to explicitly modeling them does not seem to be evaluated from a quantitative standpoint such as sensitivity runs. In the case of the diesels the fuel oil pumps, failure of which would affect mission time during LOSP, are not modeled. In addition diesel room cooling is not addressed in the model, nor is quantitative information included in the system description regarding its loss. HPCI and RCIC models also lump instrumentation into undeveloped events with no documentation of what is included in these events. Battery support models for the diesels also lump failures. From a single event failure basis the worth of these individual events may not be high, however as various equipment is taken out of service for different PRA applications these events may change significance. In addition the service water models for the diesels appear to not have pump discharge check valves modeled.	Based on our review, during the 2002 update, of the current modeling of these systems, it was concluded that the top event fault trees adequately captures the dependencies and level of detail required to provide an accurate model of system performance.
SY-07	B	The barometric condenser is not modeled for RCIC. The loss of the vacuum pump can lead to room overheating. Room cooling calculations did not evaluate steam leakage from the barometric condenser. This is an unevaluated failure mode for RCIC. There is no credit taken for operator action to open the door to the RCIC room to decrease room temperature due to steam leakage.	A review of available RCIC failure data did not find any failure data related to the barometric condenser. It is our belief that this failure is adequately accounted for in the VY failure data that combines generic data with plant specific experience.
SY-14	B	As a model simplification, a single split fraction is used to represent loss of support to either train of two train systems. This simplification has no impact on the core damage or LERF quantification, but specific component/basic event importance information is lost due to this simplification which could be detrimental for some PRA applications.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Train specific split fractions were incorporated in PRA model VY00 for SW and CS. More systems will be considered for future upgrades.
SY-15	B	The RCIC System Notebook claims that room cooling is not an issue; calculations have been done to show that the system remains operable. The Room Cooling Notebook and the system notebooks state that vendor recommendations are not exceeded. There is a problem with this in that the vendor recommendations regarding the Terry Turbines indicate that the turbine bearings need to be installed for the assessment to be valid and at that time Vermont Yankee did not have OEM bearings. There is no additional assessment of other vendor bearings.	The RCIC turbine does utilize OEM bearings. Terry Turbine was bought by Dresser-Rand, which is the manufacturer of OEM bearings. Vermont Yankee purchases their bearings from Dresser-Rand.
SY-18	B	Diesel generator cooling requirements during LOSP events is not well documented. Battery life calculations for SBO are not actually done for PRA. The qualitative assessment of battery life for 4 hours needs some more detail.	The VY main station batteries were designed for an 8 hour duration. Although battery performance test time was reduced to from 8 hours to 2 hours, the test will continue to validate that the batteries will meet or exceed the vendor's performance curve, which will continue to ensure an 8 hour mission time can be achieved.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
SY-19	B	Success criteria support documentation is not organized in a manner to allow adequate review. With regards to battery coping for a "PSA " station blackout references do not really address the situation considered.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Success criteria is now clearly defined at the system level (i.e., top event) for each accident sequence type (e.g., ATWS, S-LOCA, etc.). The information is arranged in tabular format in the new notebook: "Thermal-Hydraulic Success Criteria".
SY-20	B	The success criteria for operation of the Service Water System (Top Event SW and SWLNP) is unclear with respect to the requirement for isolation of nonessential loads. Through Top Event OS, the model assumes the operator will (guaranteed) isolate the nonessential loads whenever power is lost to Bus 1, 2, 3 or 4. This is based on procedure OT 3122 for loss of offsite power events. The hardware related to the isolation is also guaranteed to be successful (events are included in the fault tree but are set to guaranteed success). Although this approach guarantees the unavailability of non-essential loads, such as feedwater and condensate, it is not clear that this conservatism offsets the potential non-conservatism associated with successful isolation. Page 3.1.4-8 of the IPE states that it is "likely" that two SW pumps can supply both essential and non-essential loads, but no further basis for this assumption was documented. *Is it possible that* failure of isolation could lead to SW failure in some conditions?	The success of 2 of 4 pumps, whether or not isolation occurs, has been verified by calculation (VYC-1279).
SY-21	B	Basic Event numbering seems to have an extra letter associated with it at the beginning of the number. It is not clear what this means and it does not appear to be a description of the nomenclature in the support documentation.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The vast majority of basic event designations contain from 0 to 3 numbers, depending on what best matches the actual component ID. The large range of component ID's necessitate some compromise when establishing component names within the model.
SY-22	B	There seems to be a special initiator missing which would be loss of 4160V AC Bus 2. Loss of this bus would potentially cause a water level scram. In addition where possible all special initiators should have fault trees. These items were not observed in the PRA documentation.	The losses of Bus 1 and Bus 2 are accounted for in the initiating events TLP and TLPVN. The initiating event frequency for LOSP includes plant-centered events, in which loss of Bus 1 or Bus 2 would be included.
SY-26	B	A process is not described only a system description. References are not always specifically included in the documentation.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only Documentation of references are judged to be adequate for current VYNPS PSA applications. This observation will be considered during future updates.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
SY-27	B	Documentation for systems consists of a basic system description with a simplified PID attached. While system interface with the model is addressed, in some cases more detail may be needed. A case in, point is the discussion of the sequencing system for the diesel generators. If it had been more detailed it may have sufficed for a lack of detail in the service water models regarding the loading of PSW (pumps after an LOSP. Effects of initiating events are not discussed very well in the system notebooks. Under the Initiating Events documentation several system type failures are presumed to be subsumed. This interface (between systems and IE) needs to be addressed. An enhancement for the systems notebooks would be some extra discussion on system response during accident conditions.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Documentation for systems credited in the VYNPS PSA model are judged to be adequate for current PRA applications. This observation will be considered during future updates
DA-01	B	The applicability of the PLG generic database is not clear. The database notebook, PLG-0500, Revision 2, is dated July 1989. However, the data it contains is in many cases older than that. For example, DG failure is based on data through 1981. Also, there are many assumptions in this database whose applicability should be checked. For example, DG successes are estimated assuming that 1/2 of all EDGs are tested monthly and the other half are tested biweekly. Data for other components, such as control room chillers, is based on information from a given manufacturer, with no specific references given. A more contemporary database would be desirable.	Vermont Yankee risk-significant systems and components are periodically updated per Revision 0 of Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update", using plant-specific data applied to a Bayesian Update process to maintain a current estimate of component performance. In the VY PRA 2002 Update, the component data update included equipment performance history provided by Vermont Yankee's 10CFR 50.65 Maintenance Rule Program, through March 31, 2002.
DA-03	B	Use of equipment demands and operating hours from 1984-89, as currently in the PRA, may not represent current plant operation.	Vermont Yankee risk- significant systems and components are periodically updated per Revision 0 of Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update", using plant-specific data applied to a Bayesian Update process to maintain a current estimate of component performance. In the VY PRA 2002 Update, the component data update included equipment performance history provided by Vermont Yankee's 10CFR 50.65 Maintenance Rule Program, through March 31, 2002.
DA-04	B	Common-cause factors in the PLG database are probably out-of-date, and their basis is not given in PLG-0500, Revision 0, Volumes 1 & 2. Newer information is available from INEEL.	A review of NUREG/CR-5497 was performed for applicability to VY. Based on that review it was concluded that revising the CCF parameters was not warranted.
DA-05	B	There is no evidence of independent review in the data work.	Updates to the Vermont Yankee PRA, including data updates, are now proceduralized (ref: Revision 0 of Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update") and includes the requirement of signature by an independent reviewer, signifying acceptability.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
DA-08	B	The report, "1999 Vermont Yankee IPE Update, Bayesian Updating," can be improved in two respects. First is to formalize a title and cover sheet making clear the authors and reviewers. Second is to include computer file date, time, and size for codes, and for input and output files, for the Bayesian manipulation.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Updates to the Vermont Yankee PRA, including data updates, are now proceduralized (ref: Revision 0 of Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update"). The process includes the requirement of signature by an independent reviewer, signifying acceptability. The cover sheet identifies both the author(s) and reviewer(s). Computer file output from the computer program(s) used for data analysis that is required for QA and traceability are printed and included as attachment(s) to the report.
DA-09	B	The PRA includes the possibility of common-cause failure of HPCI and RCIC. This is good. However, the Beta-factor used is the same as for other pumps.	A review of the Common Cause Failure (CCF) parameters presented NUREG/CR-5497, " Common-Cause Failure Parameter Estimations", was performed for the VY PRA 2002 Update. The results were compared with the values currently used in the VYNPS PSA model, and it was found that the CCF parameters used in the VYNPS PSA model were more conservative than those suggested by NUREG-5497. Based on our review, it is our judgment that the current common cause factors are adequate, and there is not a strong basis for replacing our current common cause factors with those provided in NUREG-5497.
DA-10	B	Documentation of common-cause grouping for the IPE, and recording of such information as manufacturer and location, are excellent. However, in the IPE update, there is no evidence of specific review to ensure that none of this information has changed.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Plant configurations were reviewed for impacts of the PRA model and assumptions during the 2002 PSA model update. Plant configurations that impacted the PSA were implemented during the PSA model update.
HR-04	B	For a loss of off-site power sequence where both diesels start and both service water pumps fail to start, the HEP for starting the standby service water pump is used; however, there are timing issues associated with running the diesels without service water not incorporated into the development of the HEP that should be considered.	This HEP was quantified in the "Human Reliability Analysis for Vermont Yankee", dated January 1992. The HEP in question is TOPSSW02 -- Operator manually initiates SW pumps following component failures. Specifically, the operator places service water pump(s) in operation to supply diesel generator cooling if a component failure defeats the auto start of the service water pump designated for the diesel. Operating crews are trained to place SW pumps on for EDG cooling and not wait for "follow up+ step in OT 3122 procedure. The time frame for placing the SW pumps on line after EDG trip is assumed to be 2 hours. The action time is estimated at 2 minutes; and diagnosis time is estimated at 5 minutes. Furthermore, operation of the diesel is assumed (1) to trip on high temperature even with an accident signal present, and (2) to require SW -- but there would be indication of EDG trip before EDG failure. These assumptions are accurate, based on the design of Vermont Yankee's EDGs. Therefore, the timing constraints have been adequately addressed in the HRA.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
HR-05	B	For a loss of off-site power sequence where one diesel starts with a failure of the isolation of the non-essential loads, the HEP for starting the standby pump has not been evaluated for the time constraints that damage may occur to the diesel or to the service water pump may fail due to run-out conditions.	The assumption is that adequate cooling water flows to all essential loads is assured, even if there is a failure of the isolation of non-essential loads (via V70-19A&B or V70-20). The technical bases for this assumption is provided by results from ENVY calculation VYC-1279, with engineering judgment applied in the interpretation of the results. It is further assumed that SW pipe failures downstream of the isolation valves due to seismic activity do not occur. This is a reasonable assumption given the rarity of the event and the robust design of the piping system.
HR-06	B	There is no process described for selection of HEPs for evaluation or use in the PRA.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The process used for selection of the HEPs is described in detail in the VY-IPE Human Reliability Analysis (Feb'92), Section 2 – "Human Interaction Review Process for the IPE".
HR-08	B	Table 3.3.3.2 of the IPE defines the post initiators (dynamic) operator actions used in the model. The basis for the values from 4 different methods is provided in the HRA notebook Appendix I. In neither the table nor the appendix is the rationale provided regarding the method selected for use. Selection of one method over another should be based on the efficacy of the method for the case. If it is based on something less substantive (like taking the lowest value), can lead to inconsistent modeling of human actions.	The most appropriate estimate for each HEP was chosen by a consensus of individuals with expertise in HRA methodologies. All methods utilized provide acceptable results and none possessed any specific outstanding attributes for recommendation except that EPRI methodology is widely used and therefore became the dominant favorite for quantification of HEP point estimates.
HR-11	B	Sensitivity calculations or analysis of sequences that would be dominant contributors to core damage but for low human error rates has not been performed.	All HEPs used in Vermont Yankee's PRA were calculated using standard best-estimate HRA methodologies. The analytical models used in the HRA quantification process are based on time-reliability correlations used in past PRA applications. These models have received acceptance through use in past PRA applications. However, in order to gain a better understanding of the issue, model change request MCR-VY-0006 will provide an evaluation of any HEP with a value less than 1E-5 to determine if the estimated value has a technical bases to justify its use based upon the outcome of sensitivity calculations and the impact on core damage.
DE-01	B	System analysis documentation contains a matrix of support dependencies for the subject system. There is no overall model dependency matrix or documentation. The interface between systems is addressed only on an individual system level. This prevents complete identification of model dependencies without going through model rules (i.e., RISKMAN split fraction assignment rules) where the dependencies are included in detail but not clearly documented.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. A complete description of the RISKMAN split fraction rules and how they are applied for each top event is contained in the "Split Fraction Rule Descriptions" notebook. In addition, the applicable support system requirements for each top event are identified in the General Notes of the notebook section which describes that top event.
DE-02	B	Initiating event impacts on system models is not included in the system analysis documentation or in any other model dependency document.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The initiating event impacts on system models (i.e., top events) are provided in the "Split Fraction Rule Descriptions" notebook for the RISKMAN PRA models used at Vermont Yankee.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
DE-03	B	There did not appear to be any particular process used to identify the dependencies included in the model. In addition there is no basis documented for the dependencies presented.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The specific plant design information used to identify system dependencies are contained in the appropriate system notebooks. These notebooks were compiled during development of the initial PRA performed to support the Individual Plant Examination (IPE).
QU-01	B	Sequence 17 (6.0 x 10-8/yr.) is initiated by an IORV but involves vapor suppression failure in the sequence. Since IORV is vented to the torus, vapor suppression failure does not seem logically correct. This sequence represents a 1% error in CDF. The same sequence in the original IPE Level 2 results is Sequence 5. It involves an "early, high" release and represents a 6.5% error in LERF.	Inadvertent opening of a relief valve (Initiating Event IORV) is evaluated using the medium LOCA event tree, but top event vapor suppression is not applicable since the relief valve discharge is piped directly to the torus water volume. Vermont Yankee PRA basecase model VY02, revision 0, was modified to eliminate the potential for a non-realistic vapor suppression failure for the IORV events. This involved creating a new split fraction VSSUCC (0.00) to capture guaranteed success of vapor suppression. VS was then set to VSSUCC in the split fraction rules of the medium LOCA tree when the initiating event was IORV.
QU-02	B	A sort of CDF by initiating event contribution is not part of Vermont Yankee's standard results summary. Such a sort is useful for formal review of results and useful for communicating PRA results to plant personnel.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only Report format of Vermont Yankee's VYNPS PSA model is judged to be adequate for current PRA applications. This observation will be considered during future updates.
QU-03	B	Component importances cannot readily be calculated with the V-V RISKMAN model. This reduces the utility of the PRA. Evaluation of these importances is useful during the formal review of a new model. Such importance listings can be useful for prioritizing such components for purposes like a check valve program. Such importances can assist evaluations for online maintenance. Such importances should include RAW and F-V.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. The capability to calculate component importances was incorporated into the Vermont Yankee PRA model during conversion from the DOS version of RISKMAN to the Windows version of RISKMAN. The model change process used to achieve this capability was described in VY's "RISKMAN for Windows Implementation Plan", Section C.3, in August 2000.
QU-04	B	"RAW"-type event-tree-node importances are reported in the updated IPE summary report. It would be useful to calculate and review F-V-type event tree node importances, for a better review and understanding of the results.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. RAW, RRW and F-V importances for systems (i.e., top events) were calculated and reviewed as part of the 2002 PRA model update evaluation.
QU-05	B	The [1998] IPE Update did not include a re-quantification of the Level 2 part of the model. It is true that the IPE Update CDF increase was only 15%, and it is true that the core damage state distribution did not change ,much. However, it is prudent to proceed with the revised Level 2 quantification and review the results as the revised Level 1 results are reviewed. This provides more opportunity for results review. Furthermore, the stored revised model becomes a complete and consistent package, and that package is ready for calculations for applications which/ will often require determinations of delta's in both CDF and LERF.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. Both the Level 1 (CDF) and Level 2 (LERF) quantification results were compiled and analyzed during the 2000 PRA Model Update (Oct'00) as well as the 2002 PRA Model Update (May'03).

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
QU-06	A	When more than one operator action occurs in a sequence or a cutset, It must be determined whether the failure probability of the second operator action is affected by the failure of the first operator action. For example, the 3rd sequence in the quantification involves failure of torus cooling and failure of containment vent. Contributing to each is an operator action, and no dependence between them appears to have been modeled. Including this dependence for the portion of each failure due to operator error could increase that sequence probability approximately 30%, resulting in a 1% increase in CDF for just this one sequence. There appears to be lack of a systematic process for discovering and modeling potential dependencies.	This issue was addressed in the 2002 PRA Model Update. An assessment was performed of the dependence between dynamic operator actions modeled in the Vermont Yankee PRA, and the associated impact on CDF. The approach used to judge the level of dependence between operator actions was based on dependency level categories and conditional probabilities developed in the "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications", NUREG/CR-1278. These attributes were used to develop qualitative criteria (rules) that were used to judge the level of dependence between the operator actions. After the level of dependence between the various HEPs was judged, quantitative values associated with the level of dependence is assigned and used in a quantitative sensitivity assessment. The final dependent HEP impact on CDF was quantified by assessing only the contribution of the sequences containing the dependent HEPs where the split fraction, which contains the influencing HEP, is also failed. Based on the 5E-07 CDF screening threshold, it was concluded that this negligible change does not warrant a permanent model change.
QU-07	B	The RISKMAN PRA software allows the user to control the number of CDF scenarios that will be saved for post processing (independent of the total CDF calculation). The scenario results are used to generate top event importance, split fraction importance, and other types of reports that may provide insights to key CDF contributors. These types of reports were presented to the review team as part of the quantification documentation, but the cutoffs that control the number of scenarios saved were set too high, such that only a few hundred scenarios were saved to the database. Therefore these reports were based on a much smaller subset of the total CDF results than was possible.	The importance measures referred to (e.g. – top event importance, split fraction importance, etc.) are quantified based on the total of all minimal cutsets, regardless of bin cutoff values. The bin cutoff frequencies will affect the number of split fraction sequences saved to the database, and does not impact the computation of total CDF or of importance measures. Each initiating event has a cutoff value associated with it, which determines which sequences are used in the quantification of these results. These are typically set in the range of 1E-12 to 1E-15, which assures that many thousands of split fraction sequences are used in the quantification of risk measures.
MU-01	B	There appears to be no written maintenance and update procedures in effect. A draft procedure was provided for review. The grades for this technical element are not based on the draft procedure; however, if the procedure is issued and followed as drafted as of the date of the review, it is anticipated that many of the grades in this element would be improved significantly.	Revision 0 of VY procedure DP-0068, "PSA Update Procedure", was issued September 9, 2000. Revision 1 of DP-0068 was issued on June 20, 2002, to include enhancements to the PSA maintenance and update process. Revision 0 of Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update", was issued July 2003 and now supercedes procedure DP-0068.
MU-02	B	Section 1.1 of the draft procedure on PRA model and documentation update (DPOBXX) does not state that procedure changes are reviewed for PRA impact.	Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update", step 5.1.2 – Procedure Revisions – requires that the assigned PSA Lead Engineer shall be notified by the Emergency Operating Procedures (EOPs) responsible owner to conduct a review of any EOP changes before implementation. The PSA Lead Engineer will determine if the EOP changes potentially impact the PSA model. The PSA Lead Engineer shall ensure that the potential PSA model change is entered into the Model Change Request (MCR) database. It further states that at least annually, the assigned PSA Lead Engineer shall perform a review of Abnormal Operating Procedures (AOPs) and other procedures referenced in the PSA model to identify changes made that may impact the PSA model. The assigned PSA Lead Engineer ensures that a model change request (MCR) is created for any change that may potentially impact the PSA model and is entered into the MCR database.

F&O ID	Category	Finding/Observation	VYNPS PSA Model Impact / Resolution
MU-09	B	One of the past PRA applications was MOV risk ranking. Since that application was complete, the PRA model has been revised and additional MOVs have been added to the MOV program and ranked via expert panel. There has been no attempt to reevaluate the risk ranking of the MOVs considering the additional MOVs and model changes.	No impact on the VYNPS PSA model technical adequacy – impacts administrative details only. These re-evaluations were performed as elements of the VY PSA 2002 Update process. Entergy Nuclear Northeast procedure ENN-DC-151, "PSA Maintenance and Update", step 5.4.9 states: "Following each periodic PSA model update, Nuclear Engineering Analysis shall review all risk informed applications which may have been impacted by the update including but not limited to: System/component risk significance rankings, PSA Training Modules, Operator Lesson Plans, AOV (Reference 2.5)/MOV Risk Rankings, SAMGs, Online Risk Model."

SPSB 3

Attachment 6, Section 3.1, of the submittal dated September 10, 2003, indicates that flow-induced vibration (FIV) may cause an inadvertent safety/relief valve (SRV) opening and a stuck-open SRV. However, Section 10.5.1 indicates that no effect on loss of coolant accident (LOCA) frequencies due to the EPU were postulated. Please resolve this apparent contradiction.

Response:

Pilot leakage has been a common problem in Target Rock 3-Stage Relief Valves and has, in the industry, resulted in inadvertent valve openings and blowdown. Based on the evaluation of pilot leakage as a function of simmer margin (ref: GESIL-196, S3), it was concluded that inadequate simmer margin is the leading cause of pilot leakage. This magnitude of simmer margin will increase the seating force to minimize pilot leakage and decrease the number of inadvertent valve blowdowns or plant shutdowns for valve maintenance to avoid an inadvertent blowdown.

The subject statement in Attachment 4, Section 3.1 addresses the known past performance of the Target Rock, Model No. 67F, 3- Stage SRV, which is applicable SRV design for Vermont Yankee Plant. If the pilot valve leaks excessively it will result in an inadvertent SRV opening or possibly a stuck open SRV. Changes in flow-induced vibration with a CPPU at a specific or all valve locations may affect the pilot disc's ability to maintain alignment (e.g., cocking/tilting) with the pilot seat or have a resonance effect on the pilot's pre-load and set point adjustment spring's natural frequency (reducing effective seating force). These vibrational effects, depending upon extent and magnitude, could then lead to an increased propensity for pilot valve leakage and thus, over time, an inadvertent valve opening. This generic cautionary advisement was provided since actual FIV conditions are not clearly definable.

It should be noted that the CPPU will maintain the simmer margin unchanged, and therefore no change in the pilot valve seating force. The VY SRVs have not experienced any maintenance problems. During air actuator refurbishments each outage, no wearing or vibration induced indications have been found. Also of note, the solenoid assembly is not mounted directly on the air actuator but remotely on a pipe support. Therefore no flow induced vibrations will be transmitted to the solenoid assembly.

Operators would be alerted to a leaking pilot valve since 1) operators routinely monitor SRV tail pipe temperatures and 2) an alarm is received on high SRV tail pipe temperature. Vermont Yankee Nuclear Power Station (VYNPS) procedure OT 3121 provides guidance to the operators for a leaking SRV and an inadvertent opening of an SRV. Operations procedure OT 3121 is entered upon receiving indications of a leaking SRV. There is sufficient time for the condition to be evaluated by engineering and for operations to conduct a controlled plant shutdown as directed by OT 3121, if necessary. This would preclude an inadvertent opening of the SRV.

Inadvertent or Stuck Open Relief Valve are not new events (i.e., initiating events IORV and SORV). A Transient with inadvertent or stuck open relief valve is considered a LOCA in that the reactor response to this event would resemble that for a Medium LOCA (and is analyzed using the MLOCA event tree), except that reactor steam will be discharged to the suppression pool instead of the drywell. The expectation is that the SRV pilot valve seating force will not be significantly affected due to FIV; therefore, no increase in IORV/SORV frequencies due to this effect was assumed in the VYNPS-CPPU PSA.

SPSB 4

Attachment 6, Section 7.4.2, of the submittal dated September 10, 2003, states that a reactor recirculation system runback modification will be installed to avoid a plant trip on loss of a condensate pump or reactor feedwater pump (RFP). How has this modification been addressed in the PSA? Could malfunction of the runback circuitry cause a total loss of feedwater? If so, please describe how the total loss of feedwater initiating event frequency been modified.

Response:

Malfunction of the reactor recirculation system runback circuitry cannot cause a total loss of feedwater. Runback is initiated when any condensate pump (CP) or reactor feedwater pump (RFP) breaker is open (as determined by breaker auxiliary [position] switches) and feedwater flow is above 7.2 Mlbm/hr.

The reactor recirculation system runback modification was treated as a "risk-neutral" design change since no significant increase or decrease in risk is associated with this design change. Therefore, no changes were made to the VYNPS PSA model as a result of this modification.

SPSB 5

Attachment 6, Section 10.5.4, of the submittal dated September 10, 2003, states that the EPU plant, including ARTS/MELLLA, has an additional spring safety valve (SSV) that provides additional relief capacity for the limiting ATWS transient. This section also states that the EPU configuration is "more than adequate with one SRV [safety relief valve] OOS [out-of-service]." However, Table 10-3 indicates almost the same CDF for Accident Class IVL (ATWS sequences where core damage occurs due to overpressure failure of the Reactor Coolant System) for both the current plant and the EPU plant. Please resolve this apparent contradiction.

Response:

The impact of the new SSV on Accident Class IVL is manifested in the **'PR'** (Pressure Relief - ATWS) function of the VY PSA event trees. Due to the small contribution of **'PR'** to the Class IVL core damage frequency (CDF), a visible significant impact on the Class IVL CDF due to changes in the **'PR'** node is not expected.

Four accident scenario types contribute to the IVL accident class:

- RPT failure (failure of 'RP' node)
- FW Pump trip failures (failure of 'FT' node)
- SRV/SSV demand failures (failure of **'PR'** node)
- Other (e.g., IORV with failure to scram)

The scenarios involving failure of **'PR'** represent a small fraction (less than one tenth of one percent) of the Class IVL CDF of 3.08E-7/yr. As such, the change in Class IVL CDF resulting from changes in 'PR' modeling due to the CPPU is very small.

SPSB 6

Attachment 6, Section 6.1.1, of the submittal dated September 10, 2003, states that a grid stability study "is being performed." Please provide the frequencies of loss-of-offsite-power (LOOP) events due to plant-centered causes, grid-related causes, and weather-related causes, and describe how these values were developed (e.g., which data sources were consulted, etc.). Also describe how the probability of non-recovery from LOOP events is calculated. The NRC staff notes that recent events within the U.S. suggest that the durations of LOOP events may be significantly longer than the past.

Response:

The frequencies of loss-of-offsite-power (LOOP) events are primarily based on the original IPE approach, updated using new industry experience data from NUREG/CR-5496, Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996.

Update of the severe weather caused LOOP, initiating event TLPVN, was out of scope for the internal initiating events base model VY02.

According to NUREG/CR-5496, there were 50 plant-centered LOSP initiating events during operation between 1980 and 1996 in the US. VY experienced one LOSP event during more than 28 years of operation. Based on NUREG/CR-5496 there is no statistically significant unit-to-unit variability in 17 years of operating data, therefore it is acceptable to use generic estimate of plant-centered LOOP frequency for the VY LOOP IE frequency update. A total of 46 events were sustained (i.e., last for more than 2 minutes), and they are used as a base for the new LOOP frequency. From NUREG/CR-5496, Table 3-7, the LOOP frequency estimate is 4.00E-02 per critical year for plant centered events. (90% uncertainty interval is from 6.39E-03 to 9.73E-02).

There were a total of 6 grid-related LOOP events, according to NUREG/CR-5496, between 1980 and 1996 in the US. Only two of them occurred in the power operating mode. VY experienced zero grid-related LOOP events during power operation in more than 28 years of operation. Because of the small number of data, it was decided to use the generic estimate of grid-related LOOP frequency for VY LOOP IE frequency update. For this update, the value from NUREG/CR-5496 Table 3-10 generic grid related LOOP frequency of 1.90E-03 per reactor year was used. (Data is too sparse for uncertainty interval estimate.)

There is one LOOP initiator in the VY PRA model (i.e., TLP). The total frequency for TLP is equal to the sum of the plant-centered (PC) loss of offsite power event frequency and the grid-related (GR) loss of offsite power event frequency. The new updated TLP IE frequency was calculated as follows:

$F_{TLP} = f_{PC\_TLP} + f_{GR\_TLP}$ = 4.00E-02 * 0.90 + 1.90E-03 = 3.77E-02 [per reactor year

(5%=5.75E-03, and 95%=8.76E-02)

Multiplying by the factor of 0.90 applies the VY criticality factor to account for the average fraction of time during the year that the plant is critical and to convert the units to "per reactor year".

The VYNPS PSA model credits recovery of offsite power (top event RO in the Auxiliary Support State event tree) for station blackout-type sequences. Recovery is assumed needed before the DC-1 and DC-2 batteries deplete. Since depletion is assumed to occur after 4 hours, top event RO is defined as "recovery of offsite power to Buses 1 and 2 within 4 hours". Reference [6] is used to estimate the probability for failure to recover within 4 hours. In the VY PRA, Reference [10], plants were divided into three groups (denoted I1, I2, and I3) based on various design factors concerning offsite power sources and automatic fast transfer mechanism. New data from Reference [6] shows that sustained recovery times have no statistically significant relation to a particular plant design group. Based on a fitted distribution of recovery times of sustained TLP for plant-centered events as lognormal (Table B-8 in NUREG/CR-5496), t_{50}= 29.6 min. and EF=10.6. Using parameters relations for lognormal distribution and the MS Excel LogNormalDist function, for quantifying cumulative value for t=240 min. (4 hrs), the probability that power is not restored after 4 hours is 7.24E 02. Original IPE value is 8.0E-02.

Table B-8 from NUREG/CR-5496 presents fitted distribution of recovery times of sustained TLP for grid-related events as lognormal with median of t50= 185 min. and error factor of EF=2.14. Using parameters relations for lognormal distribution and MS Excel function LogNormalDist, for quantifying cumulative value for t=240 min., gives the probability that power is not restored after 4 hours as 2.87E-01. Original IPE value is 1.0E-01.

The probability of not recovering power after 4 hours is as follows:

$$q_{TLP} = \frac{(f_{PC\ TLP} \cdot q_{PC\ TLP} + f_{GR\ TLP} \cdot q_{GR\ TLP})}{F_{TLP}} = \frac{(3.6E\text{-}02 \cdot 7.2E\text{-}02 + 3E\text{-}03 \cdot 2.9E\text{-}01)}{3.8E\text{-}02}$$

$$q_{TLP} = 9.7E\text{-}02$$

The Vermont Yankee (VY) PSA is updated periodically. Such updates include consideration of new plant specific and industry data. Future VY PSA updates will appropriately consider new industry data regarding both LOOP frequencies and LOOP durations.

SPSB 7

Attachment 6, Section 10.5.3, of the submittal dated September 10, 2003, states that a new operator action will be incorporated into the plant procedures to satisfy certain aspects of fire (Appendix R) and station blackout (SBO) evaluations. The new action requires the operators to close the normally open torus vent valve in order to maintain ECCS net positive suction head (NPSH) when the residual heat removal (RHR) system is operating in the containment spray system (CSS) mode. Section 10.5.3 concludes that since the PSA credits torus cooling (RHR operating in the suppression pool cooling - SPC - mode), this action has no direct applicability. Please describe the circumstances (scenarios, procedural symptoms, etc.) under which the operator is directed to close the torus vent valve. Also describe the circumstances under which the operator is directed to re-open the torus vent valve. Justify not defining new human failure events address improper control of the torus vent valve.

Response:

Upon indication of a fire in the Reactor Building, the control room operators will enter Vermont Yankee Nuclear Power Station (VYNPS) procedure OP 3020 "Fire Emergency Response Procedure" (See enclosed excerpts from this procedure). Indications of a fire are:

1) An audible or visual signal from a flame, smoke, or thermal detector.
2) A local fire suppression system activation.
3) The unexpected receipt of an alarm in the Control Room on any of the following annunciators or panel:
    a. Control Room Pyrotronics Panel
    b. "Diesel Fire Pump Running"
    c. "Electric Fire Pump Running"
4) A fire has been reported to the Control Room.

OP 3020 contains separate appendices for various fire locations. The procedure directs the operator to enter the appropriate appendix for the given fire location. The appendices for the appropriate reactor building fire zones will be revised (prior to CPPU implementation) to include operator action that will close the torus vent valve. Specifically, the section titled "Operator Actions:" in each appropriate appendix will be revised (prior to CPPU implementation) adding a step that directs the operator, if a scram has been initiated, to manually initiate a Group II and Group III isolation. This task is accomplished by positioning the control switches for the respective group valves to the closed position and verifying closed indication. (The valves may already be closed if an automatic isolation was received coincident with the scram due to reactor vessel water level shrink). The torus vent valve is a Group III valve and its control switch will be taken to the closed position (even if already closed due to an automatic isolation) and will be verified closed via position light indication. All of the Group II and Group III valves' control switch and position indication are located in the control room. VYNPS procedures currently direct the operator to verify isolations following a reactor scram. If a required isolation does not occur, the operator is directed to initiate the isolation.

The above operator actions are straightforward and there is ample time for successful completion. The time available to take this action is ~ 40 minutes from the time of the reactor scram. Following the control room initial response to a reactor scram, there are no competing functions that would unduly distract the operator from taking these actions. Operators are already trained in these actions (initiating and verifying Group isolations following a reactor scram) at the plant simulator.

Indication of successful completion will be closed position indication for the normally open torus vent valve on the main control room front panel.

During a SBO, this valve will close automatically due to loss of power. The operator action would be to verify that the valve closed.

For both of the above design-bases events, the valve would not be required to be reopened until the plant is in a recovery phase.

The more conservative initial conditions assumed in the design bases calculations are responsible for identification of this operator response as necessary for successful mitigation of the fire (Appendix R) and station blackout (SBO) event sequences, in comparison with the best-estimate thermal-hydraulic calculations performed in support of the VYNPS PSA model. Specifically, the design bases calculation assumes that initial suppression pool temperature is 90°F based on worst-case. In comparison, a best-estimate value of 80°F was used for initial suppression pool temperature in the VYNPS PSA model's thermal-hydraulic evaluation. In consequence, operator action to close the torus vent valve was not identified as necessary to ensure adequate NPSH for the ECCS pumps taking suction from the suppression pool. Therefore, defining new human failure events to address improper control of the torus vent valve in the VYNPS PSA model was not necessary.

SPSB 8

Attachment 6, Section 10.5.3, of the submittal dated September 10, 2003, describes the screening process used to identify which human error probabilities (HEPs) required adjustment to account for the shortened available times due to the EPU. Table 10-5 lists 41 operator actions whose HEPs were adjusted. Please provide a complete list of post-initiator operator actions included in the VYNPS PSA model, including their HEPs, Fussell-Vesely (F-V) and risk achievement worth (RAW) importance measures for core-damage frequency (CDF) and large early release frequency (LERF), and times available to complete each action. It is important for the NRC staff to understand which operator actions were eliminated by the screening process.

Response:

The requested information is documented in the VY CPPU risk assessment report, and is reproduced here as Table RAI#8-1. Table RAI#8-1 lists all the post-initiator operator actions explicitly modeled in the VY PSA, and summarizes the following characteristics of each post-initiator actions:

- Action ID and description
- HEP
- The VY CPPU risk assessment HEP screening criteria (i.e., FVCDF, RAWCDF, FVLERF, RAWLERF, and allowable action timing)
- Level 1 or Level 2 action

As can be seen from Table RAI#8-1 below, of the 59 post-initiator actions in the VY PSA, 18 screened out and 41 were retained for explicit re-assessment in the VY CPPU risk assessment.

Table RAI#8 -1

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
AOPHRIFL	OPERATOR FAILS TO MANUALLY INITIATE HPCI AND RCIC SYSTEMS	Level 1	2.1E-3	**7.5617E-2**	**3.6355E+1**	**8.6574E-2**	**4.1389E+1**	66 min. (Trans) 35 min. (MLOCA)
EOPADMFL	OPERATOR FAILS TO MANUALLY OPEN SRV'S FOR MEDIUM LOCA	Level 1	9.1E-4	**6.6858E-3**	**8.3392E+0**	**6.6082E-3**	**8.2541E+0**	33 min.
EOPADSFL	OPERATOR FAILS TO MANUALLY OPEN SRV'S FOR TRANSIENT/SMALL LOCA	Level 1	2.1E-4	**1.6480E-1**	**7.8548E+2**	**2.0077E-1**	**9.5670E+2**	66 min.
EOPED1FL	OPERATOR FAILS TO MANUALLY OPEN SRV'S (ATWS, HCTL EXCEEDED)	Level 1	2.4E-3	1.5042E-3	1.6252E+0	1.2666E-3	1.5264E+0	**16 min.**
IABASE	OPERATOR INHIBITS ADS (ATWS)	Level 1	1.6E-3	1.0000E-3	1.6240E+0	7.2921E-4	1.4550E+0	**6.2 min.**
EOPMD1FL	OPERATOR FAILS TO MANUALLY INITIATE DEPRESSURIZATION FOR VAPOR SUPPRESSION DURING MLOCA	Level 1	9.9E-2	9.1992E-5	1.0008E+0	3.9135E-4	1.0036E+0	**10 min.**
EOPSM1FL	OPERATOR FAILS TO DEPRESSURIZE FOR VAPOR SUPPRESSION DURING SMALL LOCA	Level 1	4.6E-3	7.2092E-4	1.1560E+0	3.0667E-3	1.6635E+0	**21 min.**

Table RAI#8 -1 (cont.)

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
HOPALTINJFL	OPERATOR FAILS TO ALIGN ALTERNATE INJECTION USING CS OR CONDENSATE TRANSFER WITH SUCTION FROM CST	Level 1	3.1E-2	**3.0835E-2**	1.9627E+0	**5.3849E-3**	**1.1681E+0**	9-10 hrs.
HOPCRPFL	OPERATOR FAILS TO START A CRD PUMP	Level 1	2.6E-4	4.6442E-4	**2.7613E+0**	3.7346E-4	**2.4169E+0**	2 hrs. (after many hrs. into the event)
IA01FL	SIMPLE ACTION (OPEN DOOR) IN 10 MINUTES FOR FLOOD EVENT MITIGATION.	Level 1	1.0E-1	0.0000E+0	1.0000E+0	0.0000E+0	1.0000E+0	**10 mins.**
IA12FL	SIMPLE ACTION (OPEN DOOR) IN 10 TO 20 MINUTES FOR FLOOD EVENT MITIGATION.	Level 1	1.0E-2	0.0000E+0	1.0000E+0	0.0000E+0	1.0000E+0	**20 mins.**
IA23FL	SIMPLE ACTION (OPEN DOOR/CLOSE VALVE) IN 20 TO 30 MINUTES FOR FLOOD EVENT MITIGATION.	Level 1	1.0E-3	7.4946E-5	1.0749E+0	0.00	1.00	**30 mins.**
IA4PFL	SIMPLE ACTION (OPEN DOOR/CLOSE VALVE/STOP PUMP) AFTER 30 MINUTES FOR FLOOD EVENT MITIGATION, LOWER BOUND HEP.	Level 1	1.0E-4	**3.6784E-2**	**3.6880E+2**	**8.1385E-2**	**8.1477E+2**	>30 mins.
IOPSLMCF	OPERATOR FAILS TO INITIATE SLC SYSTEM GIVEN MAIN CONDENSER FAILED	Level 1	5.7E-2	**3.7246E-2**	1.6140E+0	**2.8882E-2**	1.4761E+0	**6 min.**
IOPSLMCS	OPERATOR FAILS TO INITIATE SLC SYSTEM GIVEN MAIN CONDENSER SUCCESS	Level 1	1.2E-3	1.6320E-3	**2.3539E+0**	1.2522E-3	**2.0388E+0**	60 min.
ISOPLLFL	OPERATOR FAILS TO ISOLATE PATH DURING LARGE LOCA	Level 1	3.1E-1	0.0000E+0	1.0000E+0	1.4395E-4	1.0003E+0	**20 min.**
JOPFIS01	OPERATOR FAILS TO INITIATE FIRE SYSTEM AND J.D. DIESEL FOR AI	Level 1	1.0E-1	**6.3446E-2**	1.4524E+0	5.3885E-4	1.0038E+0	At least 1 hr.
KOPACTFL	OPERATOR FAILS TO INITIATE SUPPRESSION POOL COOLING	Level 1	1.0E-6	1.8484E-4	**1.8558E+2**	0.0000E+0	1.0000E+0	>24 hrs

Table RAI#8 -1 (cont.)

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
KOPATWS1FL	OPERATOR INITIATES RHR IN SUPPRESSION POOL COOLING (SPC) MODE (ATWS)	Level 1	6.2E-3	2.7605E-6	1.0004E+0	0.0000E+0	1.0000E+0	**15 min.**
LCATWS1FL	OPERATOR TERMINATES AND PREVENTS ALL INJECTION SLC, CRD, AND RCIC BEFORE RPV DEPRESSURIZATION (ATWS)	Level 1	1.3E-2	**1.2200E-2**	1.6266E+0	**9.3526E-3**	1.4803E+0	**15 min.**
LCATWS2FL	OPERATOR LOWERS RPV WATER LEVEL TO TAF FOR POWER CONTROL AND RESTORES RPV LEVEL AFTER SLC INJECTION	Level 1	6.1E-3	**1.2200E-2**	1.6266E+0	**9.3526E-3**	1.4803E+0	**17 min.**
LIATWS1FL	OPERATOR RESTORES LPI POST RPV DEPRESSURIZATION (ATWS)	Level 1	1.4E-2	**8.8941E-3**	1.6264E+0	3.3421E-3	1.2354E+0	**15 min.**
MOPTVFL1	OPERATOR FAILS TO RECOGNIZE THE NEED TO VENT TORUS FOR PRESSURE REDUCTION	Level 1	1.3E-3	**3.6222E-2**	**2.8775E+1**	negligible	1.00	~5 hrs.
OPMSIVBP	OPERATOR BYPASSES MSIV ISOLATION INTERLOCKS (ATWS)	Level 1	3.1E-2	<2.76E-6	1.0000E+0	0.0000E+0	1.0000E+0	**4 min.**
QOP001FL	OPERATOR FAILS TO INITIATE/CONTROL FEEDWATER/CONDENSATE	Level 1	3.1E-3	**6.4257E-3**	**3.0561E+0**	**6.2794E-3**	**3.0084E+0**	**28 min.**
QOP003FL	OPERATOR FAILS TO OPEN MOV 64-31	Level 1	2.0E-3	1.8596E-3	1.9192E+0	2.1003E-3	**2.0381E+0**	**30 min.**
RMOPATWS	OPERATOR REOPENS MSIVs AND RESTORES CONDENSER FOR CONTAINMENT HEAT REMOVAL (ATWS)	Level 1	2.1E-1	<2.76E-6	1.0000E+0	0.0000E+0	1.0000E+0	**25 min.**
TOPSSW02	OPERATOR FAILS TO INITIATE REQUIRED SERVICE WATER PUMPS	Level 1	2.0E-3	4.0789E-3	**3.0005E+0**	2.3174E-3	**2.1365E+0**	2 hrs.
UA23FL	SIMPLE ACTION (OPEN DOOR) IN 20 TO 30 MINUTES FOR FLOOD EVENT MITIGATION (INDEPENDENT OF IOA).	Level 1	1.0E-3	0.0000E+0	1.0000E+0	0.0000E+0	1.0000E+0	**30 mins.**

Table RAI#8 -1 (cont.)

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
UA3PFL	SIMPLE ACTION (OPEN DOOR/CLOSE VALVE) AFTER 30 MINUTES FOR FLOOD EVENT MITIGATION (INDEPENDENT OF IOA).	Level 1	5.0E-4	1.2810E-3	**3.5608E+0**	0.00	9.9229E-1	>30 mins.
UAHDFL	ULTIMATE FLOODING ACTION WITH HIGH DEPENDENCE (HD) ON THE INITIAL ACTION.	Level 1	1.5E-1	1.1673E-2	1.0117E+0	**5.9249E-2**	1.0592E+0	>10 to <20 mins.
UALDFL	ULTIMATE FLOODING ACTION WITH MODERATE DEPENDENCE (MD) ON THE INITIAL ACTION.	Level 1	5.0E-2	1.4877E-3	1.0283E+0	**7.2959E-3**	1.1386E+0	>20 to <40 mins.
UAMDFL	ULTIMATE FLOODING ACTION WITH LOW DEPENDENCE (LD) ON THE INITIAL ACTION.	Level 1	1.5E-1	0.00	1.00	**6.4277E-3**	1.0364E+0	>40 mins.
UOPACM1FL	OPERATOR FAILS TO INITIATE ALTERNATE COOLING	Level 1	3.0E-2	**2.4486E-2**	1.7827E+0	1.7826E-3	1.0576E+0	12 hrs.
VDOPERROR2	OPERATOR FAILS TO DEPRESSURIZE DURING ADDITIONAL 1 HOUR	Level 2	5.0E-1	0.00	1.00	**1.1924E-1**	1.1192E+0	1 hr.
VOPRBC01	OPERATOR FAILS TO START RBCCW PUMP	Level 1	3.3E-2	1.2094E-5	1.0004E+0	7.7644E-6	1.0002E+0	**30 min.**
VROPERROR3	OPERATOR FAILS TO ALIGN RHRSW INJECTION TO RPV	Level 1	2.2E-1	0.00	1.00	**4.4761E-2**	1.1548E+0	**15 min.**
WOPTBC01	OPERATOR FAILS TO START TBCCW PUMP	Level 1	3.7E-3	**7.5709E-3**	**3.0378E+0**	**1.3903E-2**	**4.7423E+0**	**30 min.**
XOPRSAFL	OPERATOR FAILS TO RESET C.1.1A & C.1.1B FOLLOWING LOSS OF POWER	Level 1	8.0E-2	6.6836E-5	1.0008E+0	negligible	1.00	**10 min.**
YOPAC1FL	OPERATOR FAILS TO CLOSE VERNON TIE BREAKERS	Level 1	1.2E-3	3.6843E-3	**4.0501E+0**	4.6928E-3	**4.8850E+0**	**28 min.**
YOPVACFL	OPERATOR FAILS TO RESTORE MCC-8B TO THE MG SET AFTER LNP	Level 1	1.0E-1	7.0698E-4	1.0063E+0	3.5966E-4	1.0032E+0	**30 min.**
- THRESHOLD FOR ACTIONS SCREENED FROM FURTHER ANALYSIS -								

Table RAI#8 -1 (cont.)

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
AINPSH	OPERATOR FAILS TO CONTROL VENT AFTER INITIATION	Level 1	1.1E-3	9.0521E-6	1.0082E+0	0.0000E+0	1.0000E+0	3 mins. (after many hrs. into the event)
AOPHRSFL(1)	OPERATOR FAILS TO MANUALLY INITIATE SUCTION TRANSFER	Level 1	1.4E-2	1.9125E-3	1.1249E+0	1.5541E-3	1.1014E+0	13.5 min. (after ~1 hr. into the event)
BOPLPCFL	OPERATOR INITIATES LPCI/CS FOLLOWING AUTO INITIATION FAILURE	Level 1	2.7E-3	2.0998E-6	1.0008E+0	7.0675E-7	1.0003E+0	40 min.
CFHUNOEOP00X	OPERATOR FAILS TO IMPLEMENT CF EOP	Level 2	1.5E-2	0.0000E+0	1.0000E+0	negligible	1.00	~2 hrs. (after ~2 hrs. into the event)
CFINJRHRSWF L	FAILURE TO INJECT TO RPV USING RHRSW (CONTAINMENT FLOODING)	Level 2	2.4E-1	0.0000E+0	1.0000E+0	negligible	1.00	Many hours
DIOPCOOLINJECT	OPERATOR RESTORES COOLANT INJECTION AFTER CONTROL RODS MELT	Level 2	1.0E-2	0.0000E+0	1.0000E+0	7.6068E-5	1.0075E+0	~10 min. (after ~1 hrs. into the event)
DVHUDWVP-00X	OPERATOR FAILS TO OPEN DRYWELL VENT PATH	Level 2	3.5E-2	0.0000E+0	1.0000E+0	negligible	1.00	~2 hrs. (after many hrs. into the event)
IA3PFL	SIMPLE ACTION (OPEN DOOR/CLOSE VALVE/STOP PUMP) AFTER 30 MINUTES FOR FLOOD EVENT MITIGATION.	Level 1	5.0E-4	0.0000E+0	1.0000E+0	0.0000E+0	1.0000E+0	>30 mins.
ISOPSIGFL(1)	OPERATOR FAILS TO ISOLATE PATH DURING ALL EVENTS OTHER THAN LARGE	Level 2	3.2E-2	0.0000E+0	1.0000E+0	2.7282E-3	1.0821E+0	~1 hr.
RMOPBASE(1)	OPERATOR REOPENS MSIVs AND RESTORES CONDENSER FOR CONTAINMENT HEAT REMOVAL (NON-ATWS)	Level 1	1.2E-4	1.8848E-5	1.1570E+0	0.00	1.00	15 hrs.
ROPN01FL	OPERATOR FAILS TO ALIGN N2 SUPPLY	Level 1	1.4E-2	1.2028E-4	1.0085E+0	1.4452E-4	1.0102E+0	4 hrs.

Table RAI#8 -1 (cont.)

SUMMARY OF HEP SCREENING PROCESS

Operator Action ID	Action Description	Level 1 or Level 2 Action?	Base HEP	FV (CDF)	RAW (CDF)	FV (LERF)	RAW (LERF)	Allowable Action Timing
SDOPDWSPRAYFL	OPERATOR FAILS TO SPRAY DRYWELL	Level 2	1.8E-3	0.00	1.00	0.00	1.00	~1 hr.
STOPCST1FL	OPERATOR REFILLS CST FOR LONG TERM SOURCE	Level 1	8.0E-2	0.00	1.00	0.00	1.00	Many hours
TVHUVENTINGX	OPERATOR FAILS TO OPEN AND CONTROL TORUS VENT FOR CONTAINMENT HEAT REMOVAL	Level 1	1.0E-2	0.0000E+0	1.0000E+0	negligible	1.0000E+0	>4 hrs.
VDRECHARGEBATTFL	FAILURE TO RECHARGE BATTERIES USING JOHN DEERE DIESEL	Level 1	1.6E-3	0.0000E+0	1.0000E+0	negligible	1.00	> 1 hr.
YOPAC3FL	OPERATOR MANUALLY ALIGNS LOADS ON ALTERNATE DC SOURCE	Level 1	2.6E-2	0.00	1.00	0.00	1.00	> 1 hr.
ZOPCABFL	OPERATOR FAILS TO ALIGN SPARE CHARGER TO BATTERY BUS	Level 1	1.0E-2	3.2600E-5	1.0032E+0	2.4675E-5	1.0024E+0	4 hrs.
ZOPS21FL	OPERATOR FAILS TO ALIGN SPARE CHARGER TO BATTERY AS-2	Level 1	1.0E-2	1.2194E-005	1.0012E+000	1.0144E-005	1.0010E+000	4 hrs.

(1) These are the actions questioned in RAI #9.

SPSB 9

Attachment 6, Section 10.5.3, of the submittal dated September 10, 2003, states that of all the operator actions screened from further analysis, only three actions when assumed failed with a HEP of 1.0 would result in an increase in CDF by $\geq$ 1E-6/y or LERF by $\geq$ 1E-7/y. Please identify these operator actions and provide relevant information (HEPs, importance measures, and available times).

Response:

Given the VY base CDF of 7.77E-6/yr, operator actions that would increase CDF by >1E-6, if assumed to have an HEP of 1.0, have a RAW_{CDF} importance measure of >1.13 (i.e., [7.77E-6 + 1.00E-6] / 7.77E-6). Similarly, given the VY base LERF of 2.23E-6/yr, operator actions that would increase LERF by >1E-7, if assumed to have an HEP of 1.0, have a RAW_{LERF} importance measure of >1.04 (i.e., [2.23E-6 + 1.00E-7] / 2.23E-6).

As such, the three actions in question for this RAI are:

- Failure to Manually Initiate HPCI/RCIC Suction Transfer (AOPHRSFL)
- Failure to Isolate Pathway Given Containment Isolation Failure (ISOPSIGFL)
- Failure to Re-Open MSIVs for Heat Removal, non-ATWS (RMOPBASE)

These actions are noted with a footnote in Table RAI#8-1. (See SPSB-8 response above for Table RAI#8-1).

SPSB 10

Attachment 6, Section 10.5.3, of the submittal dated September 10, 2003, does not discuss how dependent operator actions were addressed in the VYNPS PSA model. Please discuss how dependent operator actions were addressed, including details such as the process used to identify dependent operator actions and the method used to develop the joint HEP.

Response:

The approach used to judge the level of dependence between operator actions is based on dependency level categories and conditional probabilities developed in the "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications" NUREG/CR-1278. Based on the NUREG/CR-1278 information, Time, Function, and Spatial attributes were judged to be the most important considerations when determining the level of dependence between operator actions within an accident sequence. These attributes were used to develop qualitative criteria (rules) that were used to judge the level of dependence (CD, HD, MD, LD, ZD) between the operator actions. After the level of dependence between the various HEPs was determined using these rules, quantitative values associated with the level of dependence was assigned and used in a quantitative sensitivity assessment. Based on this systematic framework for analysis of human action dependency, it was concluded that many HEPs are already modeled as complete dependence (CD) in the VYNPS PSA model. Likewise, many of the HEPs were judged to have zero influence (zero dependency) on other HEPs in the same sequence. Only a few were judged to have some level of dependence other than zero dependence (ZD) or complete dependence (CD) that was not already captured in the VYNPS PSA model. These HEPs were candidates for quantitative assessment to determine the impact on CDF using a 5E-07 threshold. Based on the quantitative assessment, the increase in CDF as a result of the human action dependencies was 2.62E-08. Based on the 5E-07 threshold, it was concluded that this negligible change did not justify the need for a permanent model change.

SPSB 11

Attachment 6, Section 10.5.4, of the submittal dated September 10, 2003, states that no changes were made to the system modeling due to the EPU. The original individual plant examination (IPE) submitted by VYNPS states that the plant's turbine bypass capacity is 105% of rated steam flow and that the main condenser capacity is 110% of rated steam flow. Since the EPU will increase steam flow, it appears that the EPU plant's turbine bypass and main condenser capacities have been somewhat reduced. Please discuss how these reductions affect the EPU plant's response to an anticipated transient without scram (ATWS) event. Also describe how the reduced steam dump capacity impacts the reactor trip frequency.

Response:

The original plant turbine bypass capacity was 105% rated steam flow; the capacity for the CPPU configuration is approximately 85%; however, the reduced capacity has no impact on transient or ATWS sequences in the VY PSA.

VY does not use the large turbine bypass capacity to prevent a reactor trip given a load rejection event when reactor power is above ~30% Current Licensed Thermal Power (CLTP). This is a design constraint of the plant and not just a PSA modeling approach. As such, whether the capacity is 105% or 85% has no impact on the plant transient initiating event frequency.

The reduced bypass capacity also does not impact ATWS sequences as modeled in the VY PSA:

- ATWS Sequences w/RPT Success - Following successful recirculation pump trip (RPT) during an ATWS scenario, the RPV power level is well below the 85% turbine bypass capacity, just as it is in the pre-CPPU condition. Thus, no modeling changes to the PSA are necessary.

ATWS Sequences w/RPT Failure - ATWS scenarios with failure of RPT are modeled as leading directly to core damage. This is a typical and reasonable industry PSA approach. There is no change in reactor trip frequency and, therefore, no modeling changes to the PSA are necessary.

SPSB 12

Attachment 6, Section 10.5.4, of the submittal dated September 10, 2003, states that the change in LERF is due to the change in CDF. However, the original IPE submitted by VYNPS indicates that the results of the Level 2 PSA depend on various key operator actions. Did the screening process used to identify operator actions for adjustment consider actions specific to the Level 2 PSA? Were the Level 2 PSA results recalculated to reflect changes to operator actions specific to the Level 2 PSA?

Response:

Post-core damage (Level 2 PSA) operator actions were considered in the operator action screening process for the VY CPPU risk assessment. However, no Level 2 PSA action human error probabilities required re-calculation due to the CPPU. Either the Level 2 action did not meet the screening criteria or the action is a "recovery probability" (recovery probabilities would not be adjusted based on the timing changes of the CPPU).

The Level 2 actions are included in Table RAI#8-1. (See SPSB-8 response for Table #8-1)

SPSB 13

Attachment 6, Section 10.5.4, of the submittal dated September 10, 2003, does not discuss the potential impact of the increased decay heat due to the EPU on the accident progression and containment event tree (CET) quantification. Please summarize any calculations (MAAP runs) performed for the EPU plant to confirm that the existing accident progression and CET modeling did not require any modifications. Was the release binning process, which depends in
part on the timing of containment sequences and, hence, the decay heat load, re-evaluated?

Response:

The VY CPPU risk assessment assessed the CPPU impact on the Level 2 PSA. The assessment considered the following major issues:

- Level 1 PSA input
- Accident progression
- Operator actions
- Success criteria
- Containment capability
- Release

Approximately 60 Level 1 MAAP runs and 6 Level 2 MAAP runs were performed in support of the VY CPPU risk assessment. The Level 2 MAAP runs were focused on the assessment of any significant changes in release categories. No changes to the VY PSA Level 2 accident progression logic modeling or the release binning categorization was judged necessary for the CPPU.

Level 2 Accident Progression

The CPPU does not change the plant configuration and operation in a manner that produces new accident sequences or changes accident sequence progression phenomenon. This is particularly true in the case of the Level 2 post-core damage accident progression phenomena. The minor changes in decay heat levels has a minor impact on Level 2 PSA safety functions, such as containment isolation, ex-vessel debris coolability and challenges to the ultimate containment strength. No Level 2 safety function success criteria (e.g., gpm of coolant required for in-vessel or ex-vessel debris cooling) would be changed due to the CPPU.

In addition, the CPPU does not change the containment capability assessment. The changes to the plant from the CPPU have no impact on the definition of the containment loading profiles or the likelihood of containment isolation failure. The slightly higher decay heat levels associated with the CPPU will result in minor reductions in times to reach loading challenges; however, the time frames are long (many hours) and the accident timing reductions of 10-15% due to the CPPU have an insignificant (even non-quantifiable) impact on the Level 2 results. For example, MAAP cases performed in support of the VY CPPU show that the time to reach the DW mean ultimate failure pressure (as assessed in the VY PSA) for a loss of all decay heat removal sequence is over 40 hours for the pre-CPPU condition, and this time drops to approximately 36.5 hours for the CPPU condition.

Regarding, energetic phenomena occurring at or near the time of core slump or RPV breach, such accident progression scenarios are appropriately modeled in the VY Level 2 PSA as leading directly to High magnitude releases. This is a reasonable and standard PSA industry approach. This approach would not be changed due to the CPPU.

Release Categorization Process

The VY Level 2 PSA release categorization scheme uses both release magnitude and timing (e.g., the industry LERF risk measure corresponds to the 'EHI' VY PSA release category). Release categories were assigned to the VY base PSA based on results of representative MAAP runs for many accident scenarios, and based on judgement and standard industry approaches for selected scenarios (e.g., see discussion above related to containment failures due to energetic phenomena).

The VY release magnitude classification is based on the percentage (as a function of the initial EOC inventory in the core) of CsI released to the environment; this approach is consistent with the majority of US BWR PRAs. Changes to the release categories assigned to individual accident sequences in the VY Level 2 PSA are not necessary; this was confirmed by MAAP runs. Typical post-core damage accident scenarios were run (e.g., transient with loss of all coolant injection, RPV breach, and subsequent primary containment failure due to shell melt-through) and the assigned release magnitude classifications for the scenarios did not change between the pre-CPPU and CPPU cases. While a thermal hydraulic case may be uniquely devised such that it calculates a release magnitude that is just below the border of the Moderate and High release categories so that the CPPU condition may then push it into the High category, such cases are not representative of the VY PSA (in fact, the MAAP runs performed for the VY CPPU risk assessment could not produce such a case without making unrealistic MAAP modeling assumptions).

SPSB 14

Attachment 6, Section 10.5.5, of the submittal dated September 10, 2003, indicates that a qualitative evaluation of the VYNPS fire risk profile due to the EPU was based on a review of the VYNPS fire PSA performed as part of the individual plant examination - external events (IPEEE). The information in the EPU submittal is, in fact, a quantitative analysis that adjusted the original IPEEE fire analysis results using numerical results from the internal events PSA of the EPU plant. The original IPEEE fire analysis was based on the Fire-Induced Vulnerability Evaluation (FIVE) developed by EPRI. The FIVE methodology requires both qualitative and quantitative screening of fire areas and plant responses. Were the results of the screening analyses performed in the IPEEE re-examined and confirmed for the EPU plant? Were the plant modifications specific to the EPU that are listed in Section 10.5 systematically considered for their potential impact on fire risk, either through review of design documentation or plant walkdowns?

Response:

The VY IPEEE internal fires analyses were not re-performed in support of the VY CPPU risk assessment. Similarly, plant walkdowns for internal fire issues were not re-performed in support of the VY CPPU risk assessment.

The impact of the CPPU on the different aspects of fire risk modeling were assessed based on knowledge of the VY Fire IPEEE and the modifications for the CPPU (e.g., no significant changes to combustible loadings, fire protection systems, etc. that would impact the IPEEE fire analysis). Based on this qualitative assessment, it was concluded that no unique impacts on fire risk would result from the CPPU.

A simple quantitative estimate of the change in fire risk was also performed using as input: 1) the change in internal events CDF due to the CPPU, and 2) the knowledge that fire risk is dominated by fire-induced equipment failure.

SPSB 15

Attachment 6, Section 10.5.5, of the submittal dated September 10, 2003, indicates that the EPU does not impact the results of the seismic margins assessment (SMA) performed as part of the original IPEEE. Were the plant modifications specific to the EPU that are listed in Section 10.5 systematically considered for their potential impact on seismic risk, either through review of design documentation or plant walkdowns?

Response:

The VY IPEEE Seismic Margins Analysis (SMA) was not re-performed in support of the VY CPPU risk assessment. Similarly, plant walkdowns for seismic issues were not re-performed in support of the VY CPPU risk assessment.

Although, no item-by-item re-assessment of the VY IPEEE SMA equipment was performed in support of the VY CPPU risk assessment, the VY CPPU risk assessment considered the potential impacts on a qualitative basis. No changes to equipment mountings or building structures will be made as part of the CPPU that would impact the VY IPEEE SMA conclusions. The CPPU equipment replacements are judged to be installed using anchorages that are similar to the existing equipment anchorages. The VY IPEEE SMA determined that the lowest seismic HCLPF (high confidence, low probability of failure) components for the VY seismic safe shutdown paths are the CST and the Fuel Oil Storage Tank; these insights will not be altered by the CPPU.

SPSB 16

Attachment 6, Section 10.5.6, of the submittal dated September 10, 2003, states that the impact of the EPU is to increase the shutdown CDF by about 2%. How was this value estimated without performing a shutdown PSA?

Response:

VY does not maintain a shutdown PSA. The shutdown risk impact estimate was calculated using spreadsheet calculations that calculated times to boiling and made generalized assumptions of a shutdown risk profile.

The shutdown risk impact assessment considered the following key issues:

- Shutdown initiating events
- Success criteria
- Operator actions

No new shutdown initiating events or increased potential for shutdown initiating events could be postulated due to the CPPU.

Functional success criteria was considered. No changes in success criteria that would significantly alter shutdown risk were identified.

The impact on operator action timings and offsite power recovery probabilities due to reduced inventory boiling times was assessed. The assessment considered the VY CPPU decay heat curve, boiling and boil-off times for the VY water inventories during shutdown, a typical VY outage, and the approximate contribution to shutdown CDF as a function of outage phase based on review of industry BWR shutdown risk studies.

Docket No. 50-271
BVY 04-008

Attachment 3

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263

Extended Power Uprate – Supplement No. 5

Responses to Request for Additional Information

Exhibits

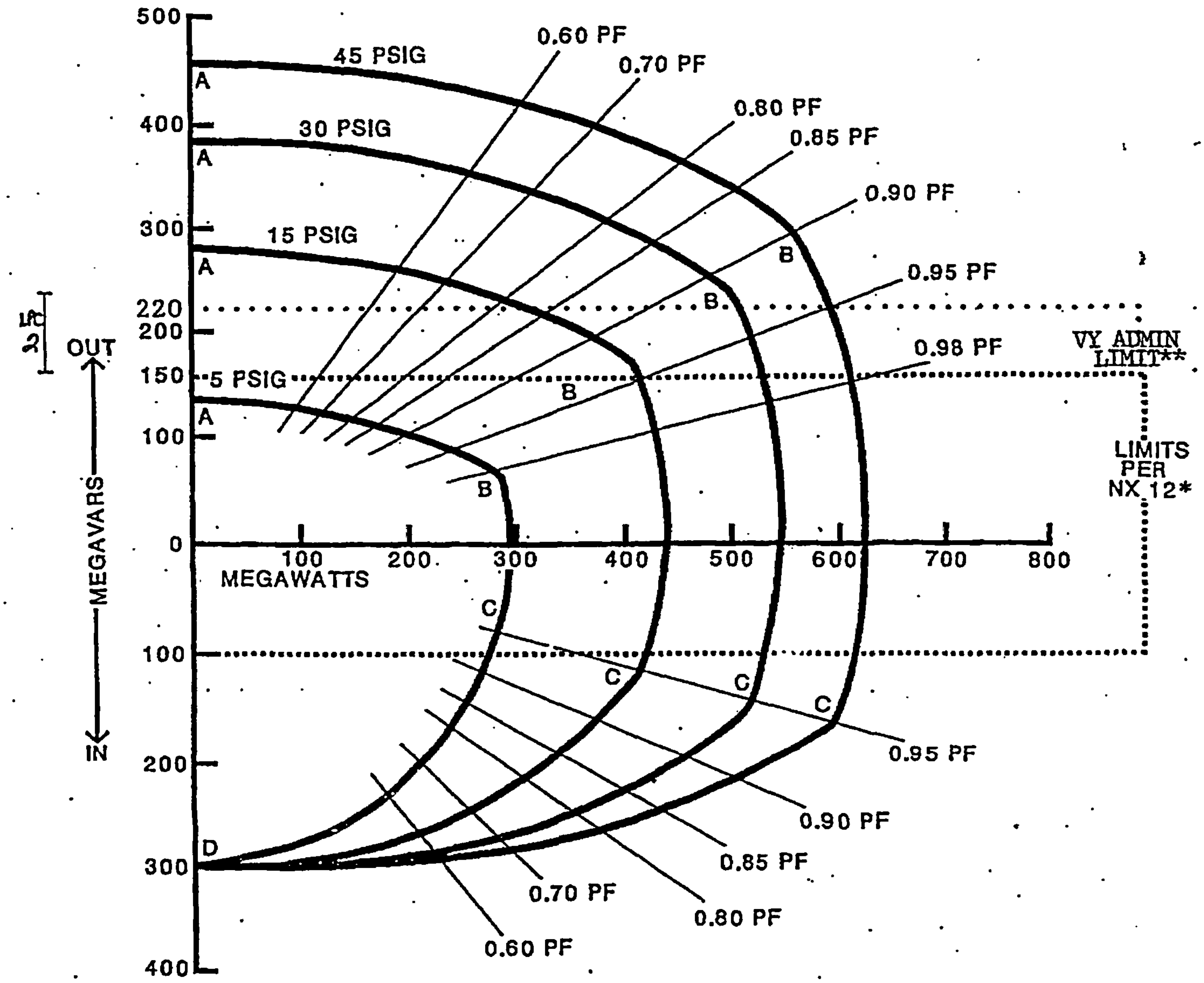
Exhibit 1

Generator Capability Curves

Fig 1

FIGURE 1
Estimated Capability Curves

ATB 4 POLE, 626,000 KVA, 1800 RPM, 22,000 VOLTS 0.90 P.F., 0.58 SCR, 45 PSIG HYDROGEN PRESSURE 500 VOLTS EXCITATION



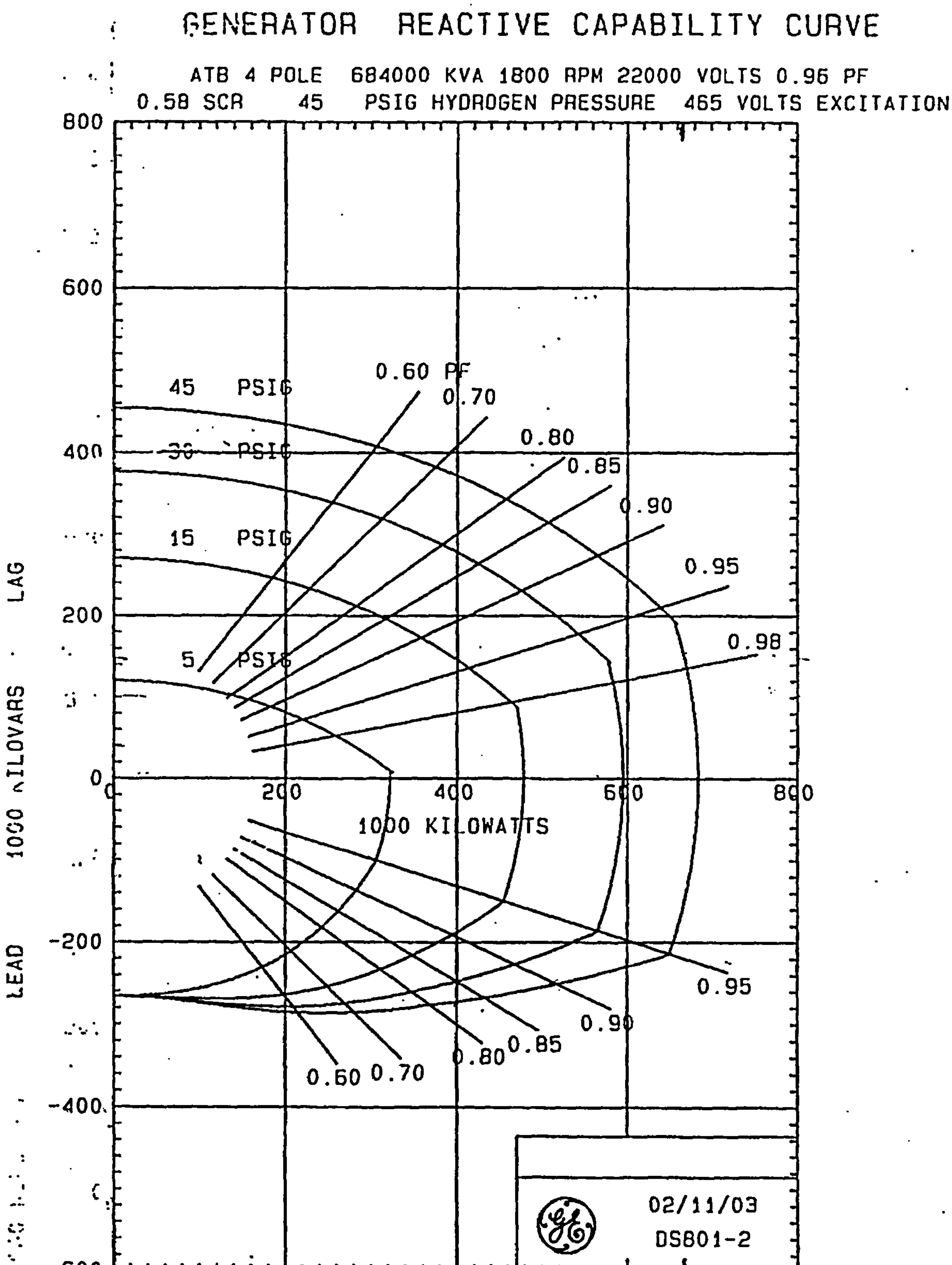
CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

LPC 2

* NEPEX PROCEDURE NO. 12 10/3/88
**VY ADMIN LIMIT TO SUPPORT STABLE GRID OPERATION IF REQUESTED BY ISO-NE

Figure 2 Fig 2:

ENERGY NUCLEAR NORTHEAST, VERMONT YANKEE UNIT #1
GENERATOR SN 180X383 ERP SO#: 1040290 CONTRACT No: VY 015408
FULL STATOR REWIND, LEAF - BTL CONV., UPRATE W/NEW H2 COOLERS



VYDC-2002-006. ENCLOSURE AB. 01 of 3

Exhibit 2

Appendix E to PP 7028

APPENDIX E

CRITERIA FOR SELECTION OF PIPING COMPONENTS FOR INSPECTION AND SAMPLE EXPANSION GUIDELINES

E.1 Inspection Planning

E.1.1 GENERAL

The outage inspection scope is determined by the FACPC using: pipe wall thickness measurements from past outages, predictive evaluations performed using the CHECWORKS computer code, industry events related to FAC, results from other plant inspection programs, and engineering judgment.

The FACPC prepares an inspection plan and identifies the inspection scope (specific components) prior to each refueling outage in accordance with outage planning milestones. This scope is used by the ISIPC for resource planning and for input to the outage schedule.

Repeat inspections are performed on piping components which have evidenced FAC damage in the past. Industry events such as a pipe rupture or discovery of eroded components may dictate a change or addition to the inspection scope. Components are added to the inspection scope based on experience or events at other operating plants as information is received. The planned inspection scope for each refueling outage may be increased or decreased during the outage based upon the quantitative inspection results of selected components.

When significant component wear is found, inspections of additional components (sample expansion) shall be performed. Sample expansion is based on the guidelines presented in Appendix E.3 below.

E.1.2 Long Term Planning

The scope of future piping inspections is dependent on the inspection results from previous outage inspections. For this reason all components to be inspected in the future cannot be scheduled several outages in advance.

With time, previous inspection results and the predictive models correlated with the inspection results will be the driving force behind inspection point selection. By then enough inspection data will have been obtained to predict, with a high degree of confidence, the locations at Vermont Yankee experiencing significant FAC damage.

Other factors to consider in planning future inspections include:

- The consequences of failure of a particular component with respect to personnel safety and plant availability.
- The margin of nominal wall thickness to code minimum wall thickness. It is a function of the original piping design and varies from system to system, and from line to line on the same system.
- Replacement of susceptible components with different piping materials. If wear rates are primarily due to piping material, replacement materials should reduce wear rates. If wear is due primarily to geometry, a partial or full redesign of the system will significantly reduce susceptibility to FAC.

E.1.3 Initial Inspections

Components selected for initial inspection shall be representative of the most susceptible systems and the component ranking within those systems. An effort to select a variety of component types should be made.

The corresponding components on parallel trains or on similar piping systems can be grouped. Each group can contain one or several piping components. At least one component from each group should be inspected.

Parallel trains of the same system should have essentially the same geometry and flow conditions. If not, the trains should be considered a separate group. Piping components downstream of each flow control valve should be considered as a separate group.

E.2 Selection Methods and/or Basis for Component Inspections

The basis for selection of specific components for examination during a refueling outage is by one or more of the following:

E.2.1. CHECWORKS Predictive Models

Components are ranked for susceptibility to FAC by the CHECWORKS computer code based on a number of factors including; component geometry, piping material, fluid environment (single-phase or two-phase flow), water chemistry, and temperature. Once actual inspection data is included the CHECWORKS model, the predicted wear rates and thickness values are statistically factored to reflect the actual wear from the inspection data.

a) For piping modeled using the EPRI CHECWORKS code without previous inspection data, select the most susceptible components on a line or section of piping for inspection.

b) For piping modeled using the EPRI CHECWORKS code with previous inspection data, select the components with the highest calculated wear rate and lowest time to minimum code wall thickness. In general, components should be scheduled for inspection by projecting the calculated wear such that it will be inspected prior to reaching 0.875 times the nominal wall thickness.

c) Components can be included in the inspection scope to help calibrate the CHECWORKS models. Generally include components from lines which have no (or a limited amount of) previous inspections data.

E.2.2 Components Identified During Previous Inspections

The Outage Inspection Reports identify components which have experienced wear and specific components to be included in future inspections. Components shall be scheduled for re-inspection for the following reasons:

- Monitoring of identified piping component wear on a component from a previous outage.
- Suspect or questionable inspection results which require confirmation.

E.2.3 Industry Experience Components

Industry experience components from other plant inspection programs or from other plant piping failures are typically identified via INPO industry operating experience (OE) or through the EPRI CHUG. Industry Experience Components include, but are not limited to locations listed below.

Large Bore Piping:

- Downstream of flow control valves.
- Downstream of orifices and /or flow meters.
- Downstream of exit nozzles.
- Downstream of feed pumps.

Small Bore Piping:

- Downstream of flow control valves.
- Downstream of orifices and /or flow meters.
- Upstream and downstream of steam traps.
- Drain and vent connections to large bore piping or components with two-phase flow.
- Last two changes in direction prior to entering the condenser.(i.e. 90 & 45 degree elbows, reducers, orifices, or globe valves).

E.2.4 Systems Not Modeled Using CHECWORKS (Susceptible–Non Modeled, SNM)

Susceptible Piping which has not been modeled using CHECWORKS (SNM) includes systems that contain lines which have unknown or widely varying operating conditions which preclude the development of accurate analytical models. These include vent and drain piping with multi-phase flow and lines subject to off normal flow conditions.

Inspection locations are selected based a combination of industry experience, plant experience, and engineering judgement. Locations should be selected for initial inspection with the objective of identifying a sufficient number and the appropriate locations to confirm system susceptibility.

Locations to inspect include:

a) Isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. Data is normally obtained from the Systems Engineering Group, (Thermal Performance Monitoring)

b) Components in susceptible piping which has not been modeled using CHECWORKS and have not received an initial inspection. Specifically:

- Downstream of orifices
- Downstream of flow control valves and level control valves.
- Nozzles
- Tees and laterals, particularly field fabricated tees and laterals
- Complex geometric locations such as components located within two diameters of each other
- Components with backing rings and counterbores.
- Components downstream of replaced components (upstream, if expander).
- Components which have been replaced in the past and not upgraded to a FAC resistant material.

E.2.5 Parametric Studies and Engineering Judgment

In general, piping systems will be modeled using CHECWORKS. However, certain piping systems or portions of lines have usage and flow rates which cannot be accurately quantified due to operating conditions which vary greatly or are controlled by remote level, pressure or temperature signals. An example is the emergency bypass lines to the condenser on the heater drain system.

Alternate methods for selection of components for inspection include parametric studies and the use of seasoned engineering judgment. Comparative studies using the CHECWORKS code or other fluid dynamics analysis tools to model a piping segment while varying parameters such as temperature, flow rate, valve position, etc. can be used to rank the effects of each parameter on susceptibility to FAC. These rankings are then used as a guide in selecting components for inspection.

Certain piping configurations and flow conditions are known to have a high susceptibility to FAC. Lines containing control valves or pressure reducing orifices which flow to a lower pressure sink such as the condenser are important to consider because of possible flashing and high velocities downstream of these components. Other conditions are not as evident, such as leakage by normally closed valves on lines considered to have no flow during normal operation.

E.3 Sample Expansion Guidelines

Expansion of the scope is required when significant wall thinning is discovered in a particular piping component. When this occurs, identical or similar piping components in parallel and/or alternate piping components shall be inspected. The EPRI sample expansion guidelines (Reference 5.4.8.) shall be used to select additional components.

"Significant wall thinning" in a piping component is determined by the evaluation of inspection data performed by Design Engineering Mechanical/Structural Dept. using DP 0072.

(1) When sample expansion is required per DP 0072, the selection of additional components to be inspected shall be as follows:

(a) Any component within two diameters downstream of the component displaying significant wear, and within two diameters upstream if that component is an expander or expanding elbow.

(b) A minimum of the next two most susceptible components from the CHECWORKS relative wear ranking in the same train as the piping component displaying significant wear.

(c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wear

(2) When inspections of the expanded sample (1) above detect additional components with significant FAC wear the sample should be further expanded to include:

(a) Any component within two diameters downstream of the component displaying significant wear, and within two diameters upstream if that component is an expander or expanding elbow.

(b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wear.

(3) When inspections of the expanded sample of (2) above detect additional components with significant FAC wear, the sample expansion of (2) above should be repeated until no additional components with significant wear are detected.

Exhibit 3

Vermont Yankee Procedure OP 3020 Excerpts

VERMONT YANKEE NUCLEAR POWER STATION

OPERATING PROCEDURE

OP 3020

REVISION 26

FIRE EMERGENCY RESPONSE PROCEDURE

USE CLASSIFICATION: **REFERENCE**

LPC No.	Effective Date	Affected Pages
1	08/19/03	Figure 1 Pg 1 of 1

UNCONTROLLED
For Information Only

Implementation Statement: N/A

Issue Date: 08/19/2003

TABLE OF CONTENTS

The plant response to fires is based upon the coordinated actions of various personnel and organizations. These actions are established within the sections of this procedure as follows:

PURPOSE

This procedure establishes the fire emergency response plan for all fire incidents at the Vermont Yankee Nuclear Power Plant.

Compliance with the requirements of this procedure satisfies the requirements of Technical Specifications 6.1.E and 6.5.A.7.

DISCUSSION

This procedure describes the general plan for response to fires occurring on Vermont Yankee plant property and establishes specific requirements for response to certain types of fire events. The objectives of the VY fire emergency plan are to (1) preserve plant operational safety and shutdown capability, and (2) protect human life.

Fires are unplanned, dynamic events. Effective planning coordinates the use of available resources (personnel and systems/equipment) in a manner that ensures a high probability for prompt fire suppression and minimal risk to plant and personnel safety.

The Shift Manager maintains overall authority for ensuring plant operational safety and shutdown capability are maintained. To assist Operations evaluation of Safe Shutdown Capability, appendices are available for most in-plant fire areas.

For the purpose of establishing fire fighting command authority, fires are classified as in-plant or on-site (defined herein). The plant Fire Brigade has primary authority for fighting in-plant fires. The responding local fire department(s) have primary authority for fighting on-site fires.

If any fire is extinguished prior to activating the Vernon Fire Department, a courtesy call should be made to the Vernon Fire Department Chief via the business number to inform him of the incident. This call would typically be performed by the Fire Protection Engineer.

If warranted by the fire, prior to sending brigade members into a IDLH environment with a working fire or any time a Cooling Tower fire is reported, the Shift Manager shall request assistance from the Vernon Fire Department. If the fire is of sufficient magnitude, the Shift Manager should request the Vernon Fire Department to call-in the Brattleboro Fire Department for additional support. If medical support is needed, the Shift Manager should request assistance from Rescue Inc. This can be accomplished by dialing 911 for all Emergencies.

All calls requesting support should use 911. If the 911 number is not available, the following direct emergency numbers are provided. Vermont Yankee's 911 address is 546 Governor Hunt Road, Vernon, Vermont.

	Emergency #	Business #
Vernon Fire Department:	603-352-1100	254-2425
Brattleboro Fire Department:	254-4543 254-4544	254-4831
Rescue Inc.	254-2010	257-7679
Mutual Aid	603-352-1100	603-352-1291

The previous business phone numbers for the listed agencies are provided for use in notifying them of incidents which may have required an emergency response, but were handled quickly enough or de-escalated so quickly that the agencies were not contacted via the emergency number. Notification in this manner ensures the appropriate agency is aware of the incident and can respond to questions posed by insurance investigators, the public, or the media. This explanation is not to be construed as a license to avoid calling for offsite assistance. For these instances use the business numbers above.

For (1) any fire not extinguished within 10 minutes, or (2) a fire that potentially affects safety systems, Control Room personnel shall declare an emergency per AP 3125, Emergency Plan Classification and Action Level Scheme.

ATTACHMENTS

1.	VYOPF 3020.01	Post-Fire Response Checklist
2.	VYOPF 3020.02	Deleted
3.	Appendix A	Fire in RCIC Zone RCIC Room Elevation 213
4.	Appendix B	Fire in Zone RB-1 Reactor Building North Elevation 213 & 232
5.	Appendix C	Fire in Zone RB-1S Reactor Building NW Corner Room Elevation 232
6.	Appendix D	Fire in Zone RB-2 Reactor Building South Elevation 213 & 232 Including HPCI Room
7.	Appendix E	Fire in Zone RB-3 Reactor Building North Elevation 252
8.	Appendix F	Fire in Zone RB-3S1 Reactor Building Northwest Elevation 252
9.	Appendix G	Fire in Zone RB-4 Reactor Building South Elevation 252 Including Steam Tunnel
10.	Appendix H	Fire in Zone RB-5 Reactor Building North Elevation 280
11.	Appendix I	Fire in Zone RB-6 Reactor Building South Elevation 280
12.	Appendix J	Fire in Zone RB-7 RB Elevation 303, 318, 345
13.	Appendix K	Fire in Area FA-4 Switchgear Room East
14.	Appendix L	Fire in Area FA-5 Switchgear Room West
15.	Appendix M	Fire in Area FZ-6, FZ-7, and FA-8 Turbine Building Including A DG Room
16.	Appendix N	Fire in Area FA-9 B Diesel Generator Room
17.	Appendix O	Fire in Area FA-10 A DG Day Tank Room
18.	Appendix P	Fire in Area FA-11 B DG Day Tank Room

19.	Appendix Q	Fire in Area FA-12 DG Fuel Oil Transfer Pump Area
20.	Appendix R	Fire in Area FA-13 Turbine Building/Rad Waste Hall
21.	Appendix S	Fire in Area FA-14 & 15 Intake Structure
22.	Appendix T	Fire in Area FA-16 Cooling Towers Including Vernon Tie
23.	Appendix U	Fire in Area FA-17 CST Area Including Area Outside B DG Room
24.	Appendix V	Response to CO_2 Discharge - Switchgear Rooms Checklist
25.	Appendix W	Response to CO_2 Discharge - Cable Vault Checklist
26.	Appendix X	Response to CO_2 Discharge - Diesel Fire Pump Day Tank Room Checklist
27.	Figure 1	Control Room Response to a Fire

QA REQUIREMENTS CROSS REFERENCE

1. None

REFERENCES AND COMMITMENTS

1. Technical Specifications and Site Documents

   a. TRM Section 6.1.E
   b. TRM 6.5.A.7
   c. Vermont Yankee Safe Shutdown Capability Analysis
   d. Vermont Yankee Safety Classification Manual
   e. Vermont Yankee Fire Hazards Analysis

2. Codes, Standards, and Regulations

   a. None

3. Commitments

   a. None

4. Supplemental References

   a. Vermont Yankee Fire Preplans
   b. YNSD Memorandum, ESG 97-004, Carbon Dioxide Worker Evaluation Revised Analyses, dated 2/4/97
   c. YNSD Memorandum, REG 97-026, Evaluation of Control Room Habitability Due to Cable Vault Room CO_2 Discharge
   d. AP 0009, Event Reports
   e. AP 0032, Duty On Call Officers
   f. AP 0125, Plant Equipment Control
   g. AP 0505, Respiratory Protection
   h. OP 2112, Reactor Water Cleanup System
   i. OP 2119, Nitrogen Supply System
   j. OP 2120, High Pressure Coolant Injection System
   k. OP 2121, Reactor Core Isolation Cooling System

PROCEDURE

A. SYMPTOMS OF A FIRE

NOTE
For the purpose of Emergency Plan Implementation, the 10 minute clock will start upon receiving a verbal report or an audible/visual alarm of a fire. (PFI9700302)

1. A fire has been reported to the Control Room.

2. An audible or visual signal from a flame, smoke, or thermal detector.

3. A local fire suppression system activation.

4. The unexpected receipt of an alarm in the Control Room on any of the following annunciators or panel:

   a. "DIESEL FIRE PUMP RUNNING"
   b. "ELECTRIC FIRE PUMP RUNNING"
   c. Control Room Pyrotronics Panel

B. REPORTING A FIRE

NOTE
Where two or more individuals discover a fire, one should notify the Control Room while the other(s) simultaneously attack the fire using portable extinguishers, if safe to do so.

1. The first priority of any individual who discovers a fire is to immediately report the location and, if known, the source of the fire to the Control Room, using the most expeditious means of communication.

2. If safe to do so, the individual may next attempt to extinguish the fire with portable fire extinguishers only.

3. If the reported fire is stated to be extinguished, the Control Room may elect to not declare a fire emergency or mobilize the Fire Brigade. However, the Shift Technical Advisor shall:

   a. immediately respond to the scene;

   b. evaluate the scene conditions; and

   c. specify any additional protective measures.

   d. contact the Fire Protection Engineer/Coordinator and have them initiate courtesy phone call to Vernon Fire Chief.

C. CONTROL ROOM RESPONSE TO A REPORT OF A FIRE

1. Implement actions per Figure 1.

D. SHIFT TECHNICAL ADVISOR/BRIGADE LEADER RESPONSE

1. Upon announcement of a fire, the Shift Technical Advisor shall:

   a. obtain a portable radio,

   b. immediately respond to the reported fire scene or Brigade Room,

   c. establish radio contact with the Control Room on the way to the scene to ensure radio is functioning.

2. For East/West Switchgear Room or Cable Vault Room, the Fire Brigade Leader shall immediately report to the effected area to determine the cause of the alarm.

3. For a verified CO_2 discharge in either the East/West Switchgear Room or Cable Vault Room, the Fire Brigade Leader shall establish a Command Post on the North Side of the Admin Building.

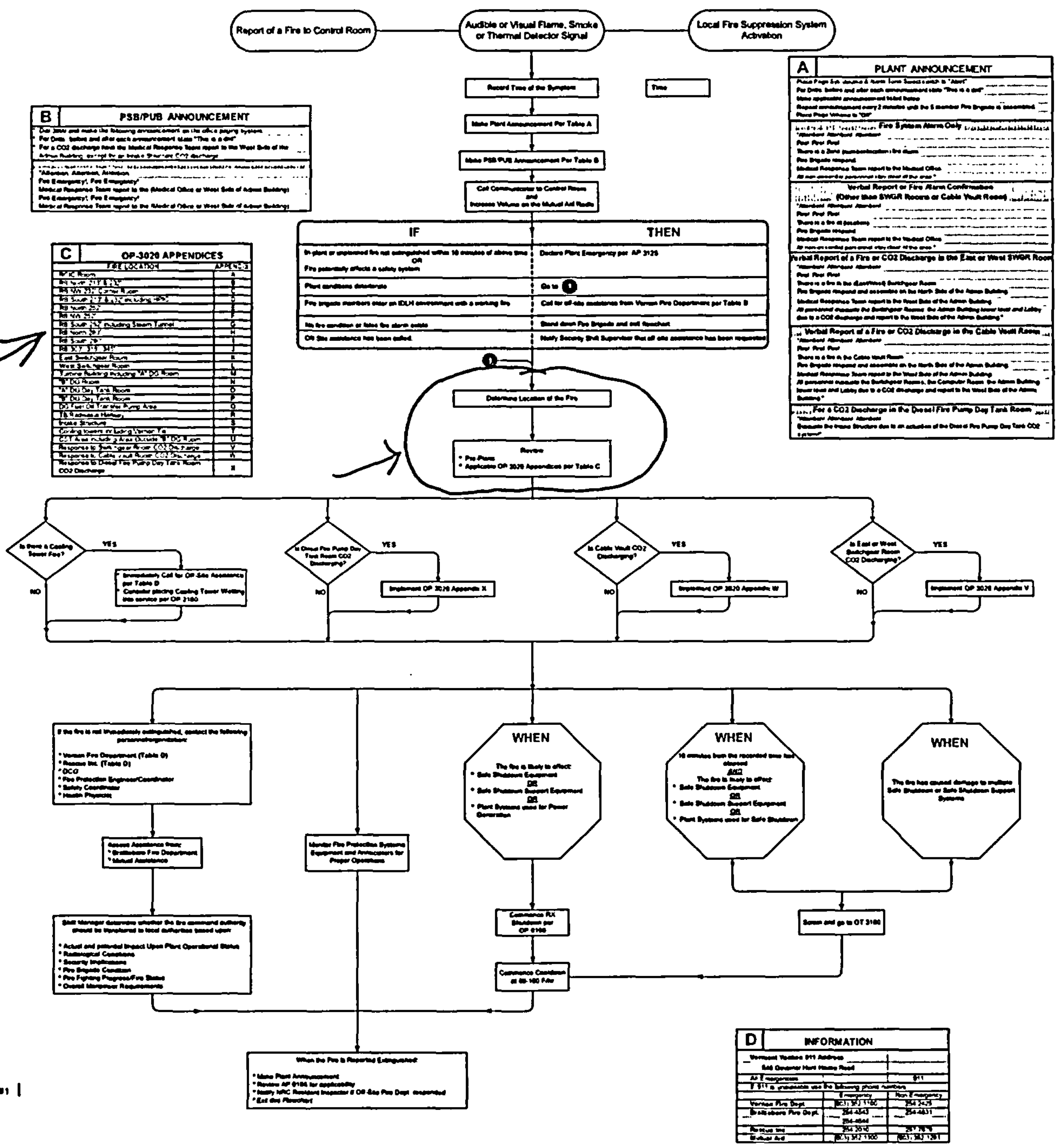
4. Upon arrival at the fire scene, the Fire Brigade Leader shall evaluate the fire and report the situation to the Control Room.

5. Depending on needs, the Brigade Leader should don turnout gear. As a minimum the FBL shall don his red helmet and incident command vest.

6. The Fire Brigade Leader shall ensure that Fire Brigade members are properly attired and equipped (including SCBAs) prior to beginning fire fighting operations.

FIGURE 1

Control Room Response to a Fire



LPC #1

APPENDIX A

FIRE IN RCIC ZONE
RCIC ROOM ELEVATION 213

DISCUSSION:

A severe fire in this zone may AFFECT the following safe safedown equipment:

RCIC including remote and Alternate Shutdown control, ADS SRV 71B, DC-2B

Safe shutdown system instrumentation affected may include:

RCIC

Specific safe shutdown indicators affected may include:

Reactor water LEVEL:	LI-2-3-72C	@ CP-82-1
Torus water LEVEL:	LI-16-19-10A	@ CP-82-1
Torus water TEMPERATURE:	TI-16-19-30	@ CP-82-1
CST water level:	LI-107-12A	@ CP-82-1
Drywell Temperature:	TI-16-19-42A	@ CP-82-1

Remaining Mechanical RCIC Process Monitoring Instrumentation in RCIC room.

No other systems that may be affected by this fire have been identified.

Use the SAFE SHUTDOWN instruments and systems listed in the SYSTEMS AVAILABLE FOR SAFE SHUTDOWN section, to evaluate and react to plant conditions as directed by the emergency procedures.

The USE CLASSIFICATION of this appendix is **REFERENCE USE**.

OPERATOR ACTIONS:

CAUTION
Spurious actuation, or loss of electrical operation, of SRV-71B may occur during a fire in this zone.

1. Increase monitoring of Control Room Panels for all normally important plant parameters, including instrumentation listed above likely to be affected by the fire.

2. Determine from updated information and from communication with Fire Brigade, the severity of the fire.

   a. Take appropriate actions as dictated by EOPs, the Emergency Plan, and Technical Specification requirements.

3. **If an in progress fire has caused damage to multiple safe shutdown systems or safe shutdown support systems, initiate a reactor scram.**

4. **If a fire that is likely to affect safe shutdown, safe shutdown support, or other key plant system used for safe shutdown, is not extinguished within 10 minutes a Reactor scram shall be initiated.**

5. If a fire is likely to affect safe shutdown, safe shutdown support, or other plant system used for power generation a Reactor shutdown shall be initiated.

6. If a reactor scram or shutdown was initiated per the above steps, begin a reactor cooldown to Cold shutdown at a rate of 80 to 100 Degrees per hour.

7. Perform the below actions as soon as practical:

   a. Check closed or close valves:

      RCIC-131 STEAM SUPPLY
      RCIC-30 MIN FLOW
      RCIC-39 TORUS SUCTION
      RCIC-41 TORUS SUCTION
      RCIC-16 STEAM ISOLATION OUTBOARD
      RCIC-15 STEAM ISOLATION INBOARD

   b. Open the feeder breaker on DC-2 to DC-2B in the Cable Vault.

8. If an SRV inadvertently opens enter OT 3121.

SUBSEQUENT ACTIONS:

1. If RBCCW is not available, establish RHR pump seal cooling per ON 3147 prior to initiating shutdown cooling.

2. If necessary, open RCIC-27 ACB and manually close RCIC-27.

SYSTEMS AVAILABLE FOR SAFE SHUTDOWN:

The following safe shutdown systems have been analyzed to be free of fire damage in this zone. Other systems listed below are not analyzed for this fire, but should be considered available for use.

<u>POWER SOURCES:</u>

SAFE SHUTDOWN:	All emergency AC buses and distribution, DG A&B, Vernon Tie, DC-1, 1A, 1B, 1C, DC-2,2A,2C, 24VDC ECCS A&B, DC-1AS & 2AS
OTHER:	Off-site normal power, Non-vital Buses and distribution

<u>COOLANT INVENTORY:</u>

SAFE SHUTDOWN:	HPCI, LPCI A&B, CS A&B
OTHER:	Condensate and feedwater, CRD, Condensate transfer

<u>REACTOR PRESSURE:</u>

SAFE SHUTDOWN:	HPCI, ADS SRV 71A,C,& D
OTHER:	Turbine Pressure control

<u>DECAY HEAT REMOVAL:</u>

SAFE SHUTDOWN:	RHR A&B on Torus Cooling or Shutdown Cooling
OTHER:	Main Condenser via Turbine Pressure control

<u>AUXILIARY SUPPORT:</u>

SAFE SHUTDOWN:	RHRSW A&B, SW A&B
OTHER:	Circ Water, TBCCW, Instrument air, Turbine LO, RBCCW

APPENDIX A (Continued)

INSTRUMENTATION:

SAFE SHUTDOWN:

Process Monitoring

Reactor PRESSURE:	PR-6-96 & PI-2-3-56A	@ CRP 9-5
Reactor water LEVEL:	LI-2-3-86 LR-6-98 LT-2-3-73A(M)	@ CRP 9-4 @ CRP 9-5 @ CAB 25-6B
Torus water LEVEL:	LI/PI-16-19-12A & B	@ CRP 9-3
Torus water TEMPERATURE:	TI-16-19-33A & C	@ CRP 9-3
Torus PRESSURE:	PI-16-19-36A & B	@ CRP 9-3
Drywell TEMPERATURE:	TR-16-19-45 & TI-16-19-42B	@ CRP 9-25
Drywell PRESSURE:	LI/PI-16-19-12A & B	@ CRP 9-3
CST water LEVEL:	LI-107-5 LR-23-73	@ CRP 9-6 @ CRP 9-3

OTHER: Balance of plant (BOP) instrumentation, and Nuclear Steam Supply System (NSSS) instrumentation.

FINAL CONDITIONS:

1. The plant is in a safe, stable condition.

Exhibit 4

Ecological Studies of the Connecticut River Vernon, Vermont Report 32 May 2003

NORMANDEAU ASSOCIATES, INC.
25 Nashua Road
Bedford, NH 03110-5500
(603) 472-5191
(603) 472-7052 (Fax)
www.normandeau.com

Ref. No 18980.010/004
29 May 2003

RECEIVED
JUN 3 2003
By

Ms. Lynn DeWald
Environmental Program Lead
Entergy NuclearVermont Yankee, LLC
Governor Hunt Road
P.O. Box 157
Vernon, VT 05354-0157

Dear Lynn:

Enclosed please find two copies of the final report "ECOLOGICAL STUDIES OF THE CONNECTICUT RIVER VERNON, VERMONT REPORT 32 MAY 2003". Report 32 presents findings of the January through December 2002 NPDES monitoring program conducted by Normandeau Associates, Inc. on behalf of Entergy Nuclear Vermont Yankee, LLC to satisfy one of the monitoring and reporting requirements of the Final Discharge Permit #3-1199 (NPDES number VT0000264) for 2002. I have provided you with both hard copies and CD copies of Report 32. I have also sent one CD copy of the report to Ms. Carol Carpenter of the Vermont Agency of Natural Resources, and one CD copy to each of the Vermont Yankee Environmental Advisory Committee (EAC) members listed below.

Sincerely,

NORMANDEAU ASSOCIATES, INC.

Mark T. Mattson

Mark T. Mattson, Ph.D.
Vice President

Enclosure: as stated

CC:
Ms. C. Carpenter, VT-ANR
Mr. D. Burnham, VT-DEC
Mr. K. Cox, VT-DFW
Mr. R. Estabrook, NH-DES
Mr. W. Ingham, NH – DFG
Mr. C, Slater, MA-DFW
Mr. R. Maietta, MA-DEP
Ms. J. Rowan, US-FWS

ECOLOGICAL STUDIES OF THE CONNECTICUT RIVER VERNON, VERMONT REPORT 32

MAY 2003

ECOLOGICAL STUDIES OF THE CONNECTICUT RIVER VERNON, VERMONT REPORT 32

JANUARY – DECEMBER 2002

VERMONT YANKEE NUCLEAR POWER STATION
BRATTLEBORO, VERMONT

Prepared for
ENTERGY NUCLEAR VERMONT YANKEE, LLC
320 Governor Hunt Road
Vernon, Vermont 05354

Prepared by
ENTERGY NUCLEAR VERMONT YANKEE, LLC

and

NORMANDEAU ASSOCIATES, INC.
25 Nashua Road
Bedford, NH 03110

R-18980.010

May 2003

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1.0 INTRODUCTION

This report is submitted on behalf of the Entergy Nuclear Vermont Yankee, LLC (ENVY) and fulfills the requirements of the Final Discharge Permit #3-1199 (NPDES number VT0000264).

This is the second annual report submitted under the five-year discharge permit issued in August 2001 and the first presented under the amended (transferred) discharge permit issued in May 2002 to ENVY. Presented in this report are the results of the monthly thermal compliance monitoring and the methods and results of the environmental monitoring program, including water quality, macroinvertebrates, fish, and zebra mussels. The NPDES permit environmental sampling stations referred to in this report are presented on the NPDES sampling stations map (Figure 3-1).

ENVY experienced two outages during 2002. The first one occurred from 10 May until 27 May, necessary maintenance was required. The second outage took place from 5 October through 25 October for refueling. Larval fish and impingement sampling was not conducted during either outage.

At the request of the Vermont Department of Fish and Wildlife, no adult American shad were collected or processed from the Vernon Dam fish ladder during the spring of 2002. Low passage numbers at Vernon Dam during the 2002 spring season prompted these actions. Adult American shad will be processed during the 2003 migration season unless we are directed not to do so by the Vermont Department of Fish and Wildlife.

Juvenile American shad studies were conducted during 2002; the final report outlining this study will be submitted under separate cover to the Environmental Advisory Committee in spring 2003 as Analytical Bulletin No. 79. The bulletin is titled "Abundance of juvenile American shad in the Vernon pool during 2002" Entergy Vermont Yankee/Connecticut River System Analytical Bulletin 79.

One task-oriented macroinvertebrate study occurred during the summer and fall of 2002. The final report outlining this study will be submitted under separate cover to the Environmental Advisory Committee in spring 2003 as Analytical Bulletin No. 80. The bulletin is titled "Evaluation of Macroinvertebrate Populations Using Artificial Multiplate Samplers in the Vernon Pool 2002" Entergy Nuclear Vermont Yankee/Connecticut River System Analytical Bulletin 80.

This report was produced as a collaborative effort between ENVY and Normandeau Associates, Inc.

2.0 COMPLIANCE WITH THERMAL STANDARDS

2.1 THERMAL STANDARDS

The operational mode of Vermont Yankee's cooling water system is related to calendar dates and ambient Connecticut River water temperatures as specified in Vermont Yankee's discharge permit (Permit No. 3-1199, NPDES Number VT0000264) effective 29 August 2001. During the 16 May through 14 October (summer) period of each year, Vermont Yankee is permitted to discharge heat to the river within the following thermal standards (A.6.b of the NPDES permit):

Connecticut River Temperature at Station 7 (T7)	Calculated Increase in River Temperature above Ambient
T7>63°F	2°F
63°F(T7>59°F	3°F
59°F(T7>55°F	4°F
55°F(T7	5°F

During the (winter) period of 15 October through 15 May of each year, Vermont Yankee is permitted to discharge heat to the Connecticut River within the following thermal standards (Section A.6.a of the NPDES permit):

1. the temperature at Monitor Station 3 during open cycle operation shall not exceed 65°F
2. the rate of change of temperature at Monitor Station 3 shall not exceed 5°F per hour, and,
3. the increase in temperature above ambient at Monitor Station 3 shall not exceed 13.4°F.

The river discharge near Vernon is regulated by Vernon Dam and Hydroelectric Station to remain at or above 1250 cubic feet per second (cfs) or inflow if less than 1250 cfs. Since the theoretical maximum increase in temperature due to Vermont Yankee's thermal discharge at a river flow of 1250 cfs is 12.9 °F, these standards, in effect, permit open cycle condenser cooling without cooling tower operation when ambient river temperatures are less than 52.1 °F during 15 October through 15 May. If ambient river temperatures are greater than 52.1 °F, the amount of heat discharged to the river can be reduced by using the cooling towers if the river flow is low.

2.2 METHODS OF DEMONSTRATING COMPLIANCE

Compliance with the 15 October through 15 May criterion that limits open cycle operation to times when the downstream temperature is less than 65°F was demonstrated by examination of Connecticut River temperature and plant operating data. Rate of change of temperature is defined in the NPDES permit as the difference between consecutive hourly average temperatures. Measurements recorded in the Connecticut River below the Vernon Dam (Station 3) were used to calculate these hourly rates of temperature change.

Increase in temperature above ambient is defined in the NPDES permit as a plant-induced temperature increase as calculated by *equation 1-1 in the report 316 Demonstration* (Binkerd 1978, Downey and Binkerd 1990). This equation is based on the principle of conservation of energy, a principle which is integral to the computer simulation of the Vermont Yankee/Connecticut River system. Using measured upstream river temperature, plant operating data and core thermal power, the amount of heat discharged to the river was calculated. Then, using thermodynamic and hydrodynamic principles and river discharge information, the mixed river temperature increase was calculated and compared with thermal standards.

Equation 1-1, rearranged for ease of computer computation using input from the plant environmental thermal sensor network, is as follows:

Equation 1a $H\_RECIRC_t = (TCI_{t-1} - TCI_t) * 472640.5 / 3600$

Equation 1b IF $(TCIT_{t-1} - TCIT_t) < |0.1|$ THEN $H\_RECIRC_t = 0$

Equations 1c IF $CWP_t = 1$ AND $CWBP_t = 0$ THEN $PUMP\_CAP_t = 267.38$

IF $CWP_t = 2$ AND $CWBP_t = 0$ THEN $PUMP\_CAP_t = 304.14$

IF $CWP_t = 2$ AND $CWBP_t > 0$ THEN $PUMP\_CAP_t = 267.38$

IF $CWP_t = 3$ AND $CWBP_t = 0$ THEN $PUMP\_CAP_t = 259.58$

IF $CWP_t = 3$ AND $CWBP_t > 0$ THEN $PUMP\_CAP_t = 254.01$

Equation 1b $H\_RIV_t = (PUMP\_CAP_t * CWP_t) * ((TCO_t - TCI_t) - (CWBP_t / CWP_t) * (TCO_t - (TETO_t + TWTO_t) / 2)))$

Equation 1: $DELTA\_T_t = (H\_RIV_t + H\_RECIRC_t) / Q_t$

where,

H_RECIRC_t = heat content of the circulating water system and cooling towers in cfs °F at time interval t

TCI_{t-1} = condenser inlet temperature in °F at time interval t-1

TCI_t = condenser inlet temperature in °F at time interval t

CWP_t = number of circulating water intake pumps operating in time interval t

$CWBP_t$ = number of cooling tower booster pumps operating in time interval t

$PUMP\_CAP_t$ = pump capacity of the circulating water intake pumps in cfs

H_RIV_t = heat content of the cooling water discharge in cfs °F in time interval t

TCO_t = condenser outlet temperature in °F at time interval t

$TETO_t$ = east cooling tower outlet temperature in °F at time interval t

$TWTO_t$ = west cooling tower outlet temperature in °F at time interval t

$DELTA\_T_t$ = average simulated Connecticut River temperature increase at Station 3 in °F in time interval t

Q_t = average Connecticut River discharge observed at Vernon Dam in cfs in time interval t

Vermont Yankee's Azonix temperature monitoring systems at Stations 3 and 7 are linked to the Station's process computer. This allows Vermont Yankee operators to utilize real time, accurate temperature data for thermal compliance. It also allows Vermont Yankee's Environmental Group an opportunity to generate thermal compliance reporting. Self-contained WaDaR thermistor units remain in the river at Stations 3 and 7 as the back-up temperature recorders to the AZonix. The simulation is based on electronically acquired five-minute river discharge data from the Vernon Dam and Vermont Yankee's five minute observations of thermal temperatures at Stations 3 and 7 and thermal heat discharge to the river.

2.3 THERMAL IMPACT

Figures in this section illustrate the principle of conservation of energy as applied to the Vermont Yankee/Connecticut River system. Figure 2-1 depicts core thermal power produced and plant discharge flow by Vermont Yankee in 2002. This data was obtained from five minute records supplied by Vermont Yankee. The licensed maximum reactor core thermal power is limited to 1593 megawatts. About one-third of this power was converted to electrical power, while the remainder was transferred as heat to the atmosphere via the cooling towers, or discharged to the river (Figure 2-2). Leaking fuel was identified in December 2001 and resulted in a mid-cycle shut down (outage) that began on May 11, 2002 and lasted 11 days. Subsequent to the mid-cycle outage, the Station ran uninterrupted until the start of the scheduled 21 day refueling outage in October 2002. The refueling outage began on October 5, 2002 when the generator was taken off line. The generator was returned to service October 27, 2002. Otherwise the plant remained at full power throughout 2002, with occasional brief periods of power derating.

Figure 2-3 is a plot of hourly Connecticut River discharge for the Vernon Hydroelectric Station Dam in Vernon, Vermont during 2002. The hourly average Connecticut River discharge was computed using five minute observations obtained by Vermont Yankee through their computer system from sensors installed at the Vernon Dam. When the flows were above 32,000 cfs electronic hourly river flow data was obtained from PG&E New England Generation.

Table 2-1 contains the average daily and monthly Connecticut River discharge computed from the hourly observations obtained for 2002 as described above. For discharge greater than 12,000 cfs, a rating curve was used by Vernon Dam to convert stage height to discharge. The rating curve was the same one used by the USGS prior to abandoning the Vernon gauging station (Aquatec 1995). This curve is believed to be sufficiently accurate because backwater from the Northfield Mountain Pump Storage Facility and the modification at Turners Falls Dam have had little impact on stage height near Vernon Dam during times of high discharge (Aquatec 1995). Below 12,000 cfs, discharge data were obtained from turbine rating curves at Vernon Station. The peak daily Connecticut River average flow for 2002 was 59,113 cfs, which occurred on 16 April 2002 compared to 69,762 cfs on 23 April 2001. The hourly average flows are represented in Figure 2-3. The peak hourly average Connecticut River flow occurred on 16 April 2002 at 65,745 cfs. The lowest hourly Connecticut River flow at Vernon Dam was 1049 cfs observed on 29 August 2002.

The simulated increases in Connecticut River temperature at Station 3 due to Vermont Yankee's operation are plotted for each hour of operation in Figure 2-4. Vermont Yankee's discharged heat remains dependant upon reactor power and plant operational mode. During normal full power operations these values range from 1035 to 1120 mwt. Connecticut River discharge (Figure 2-3), Vermont Yankee daily average discharge flow (Figure 2-2) and river temperature increase (Figure 2-4) illustrates that for a constant heat rejection rate to the river, the temperature increase is inversely proportional to the river discharge. Vermont Yankee's operation remained at or below the permit standards for all of 2002 except for one occasion on 5 October 2002 when Vermont Yankee operators secured a piece of Station equipment to support work. Because this equipment was secured and therefore not operable, some of the automated input to the Project SAVE thermal calculation was determined to be unreliable. The control room staff observed unrealistic changes in river temperature and began manual calculation of the rise in river temperature due to the Station's discharge. This event was: 5 October 2002 1100-1200 DST, +0.05 degrees F (above permit limit), Permit Limit + 2.0 degrees F.

During the 15 October through 15 May (winter) period when the thermal discharge permit limit was 13.4° F, the maximum simulated river temperature increase observed was 12.7° F on 23 January 2002 at 0300 when the river flow was 1,367 cfs.

Hourly average temperatures measured at Station 7 and Station 3 are plotted on Figure 2-5. Station 7 is well upstream of the plant, and water temperatures are unaffected by the plant's thermal discharge. Heat discharged from the plant was well mixed at Station 3, due to passage through the Vernon Dam. Temperatures measures at Station 3 reflected both the natural and plant-induced changes in temperature between the upstream and downstream locations, and never exceeded the 65° F limit during the period October 15 through May 15 (Figure 2-5). The rate of change of temperature at Station 3 did not exceed ±5°F permitted change per hour.

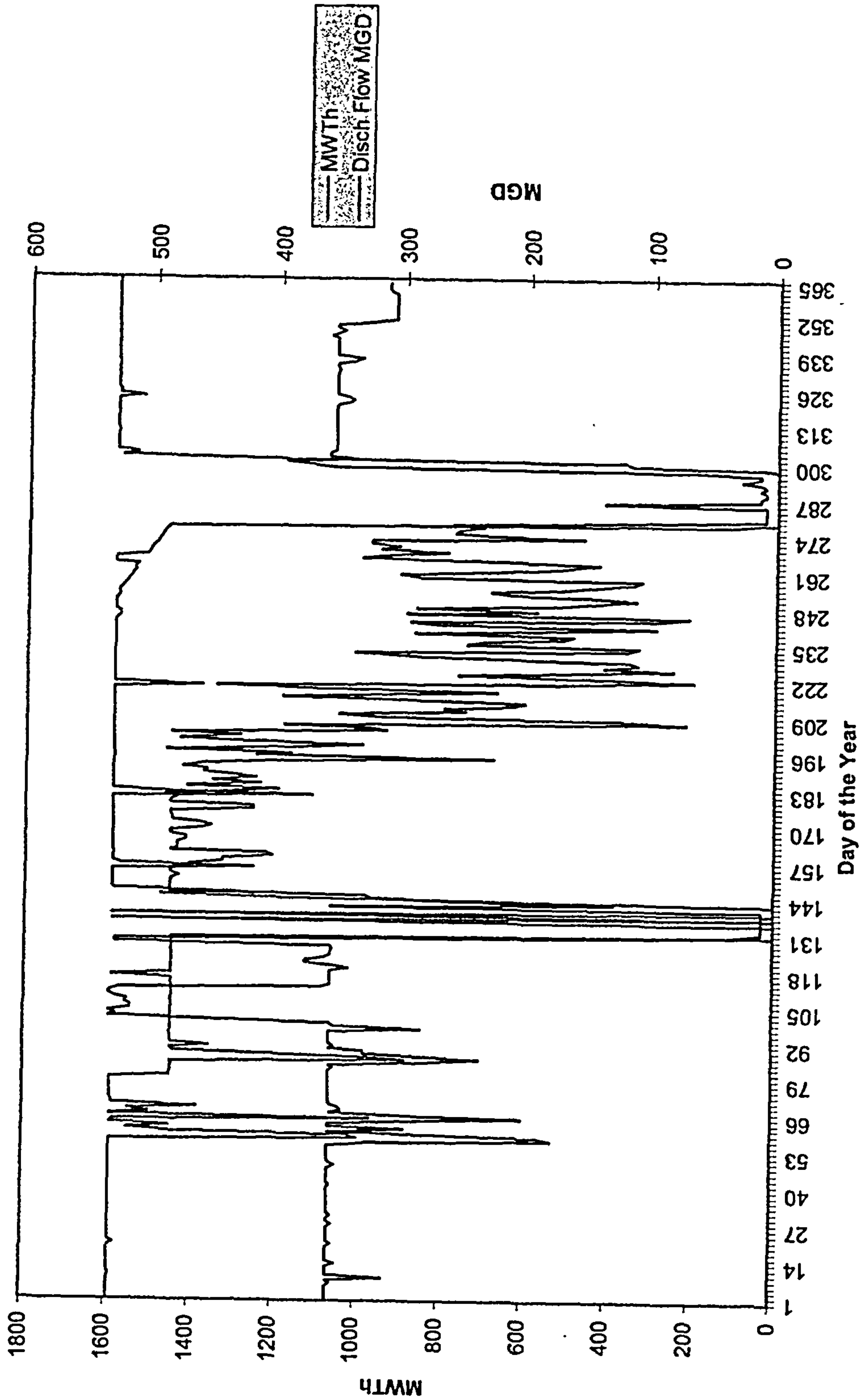

Figure 2-1. Vermont Yankee Core Thermal Power and Plant Discharge Flow 2002.

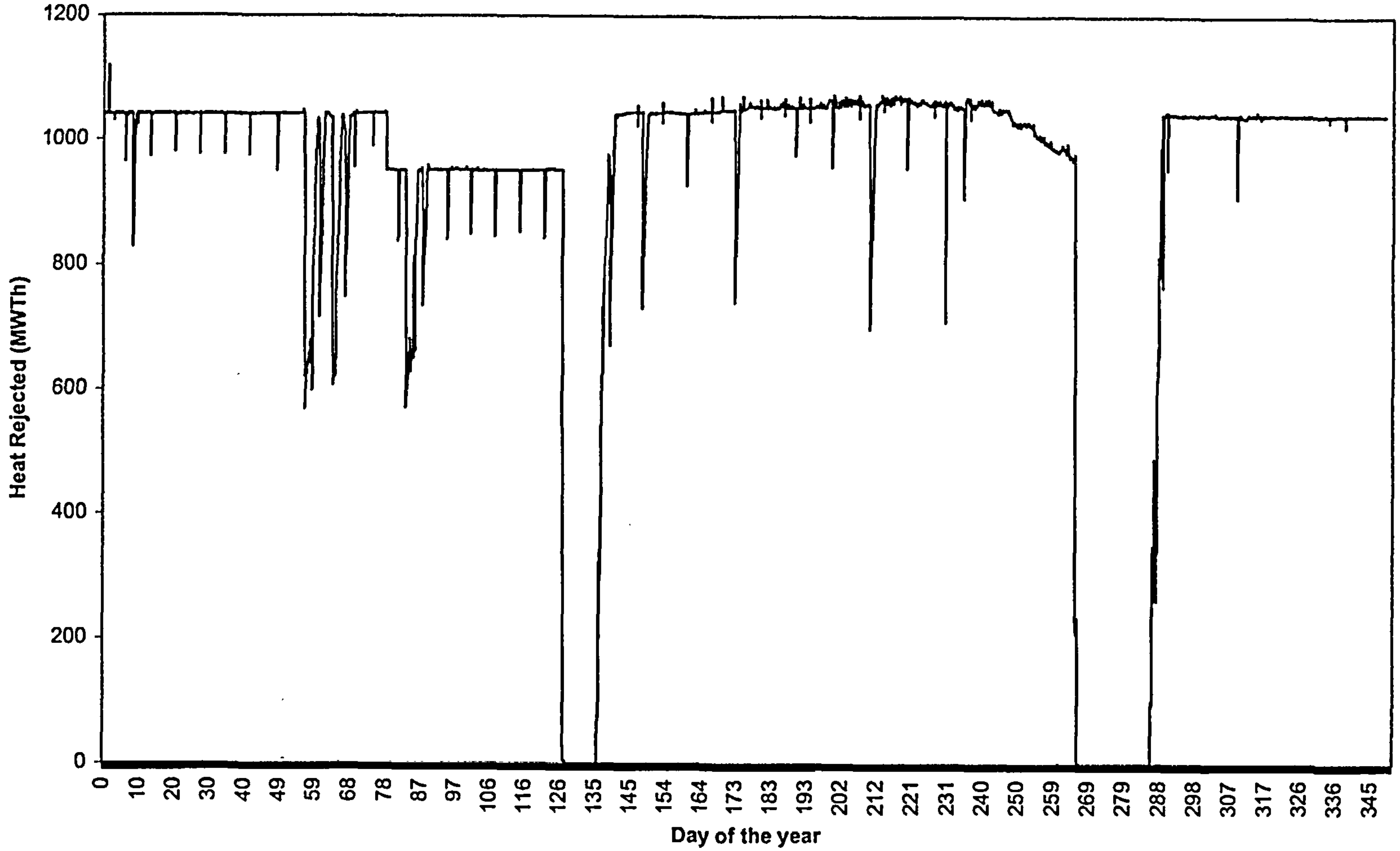

Figure 2-2. Hourly Average Heat Rejected by Vermont Yankee's Condenser During 2002.

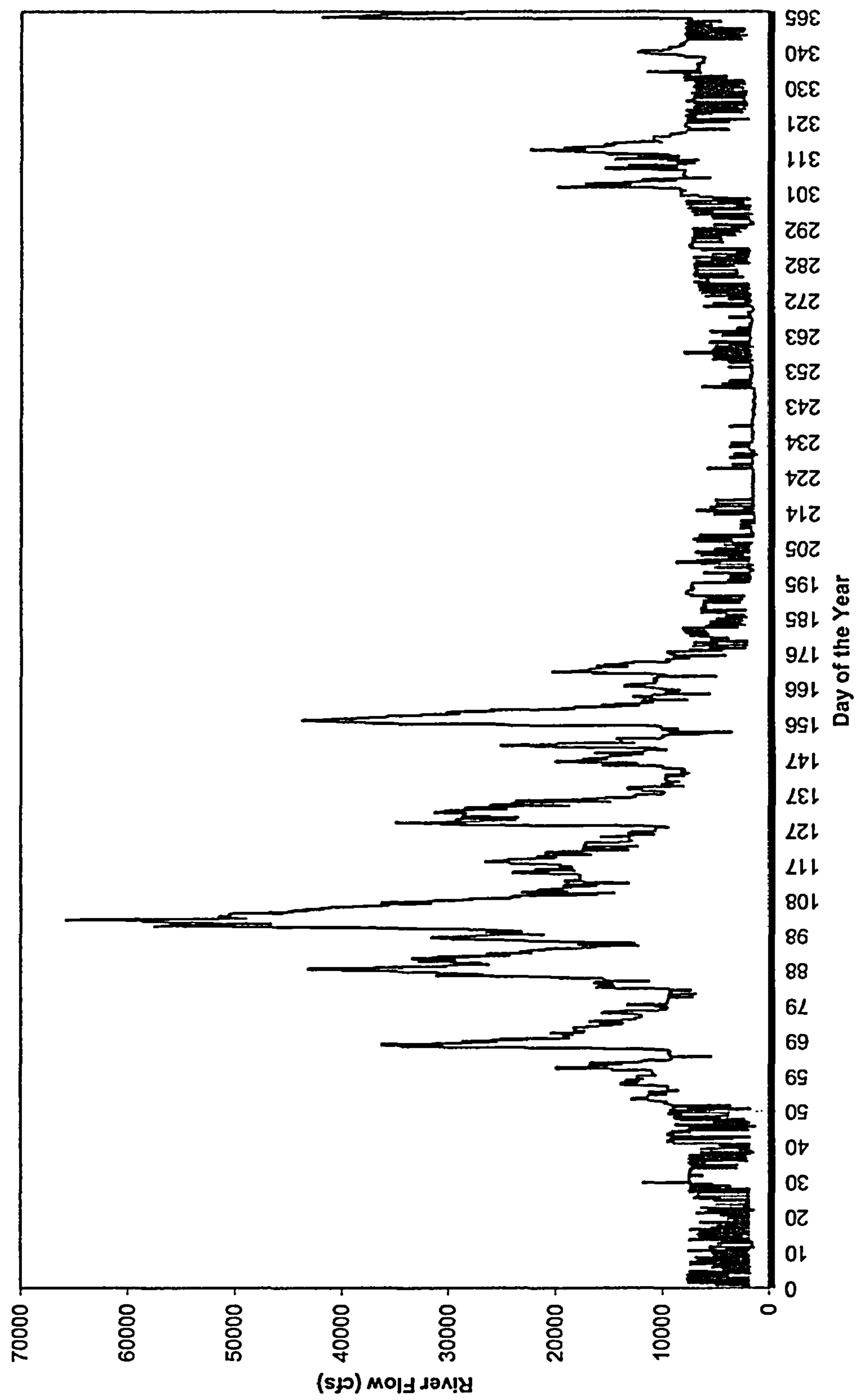

Figure 2-3. Hourly Average Connecticut River Flow During 2002.

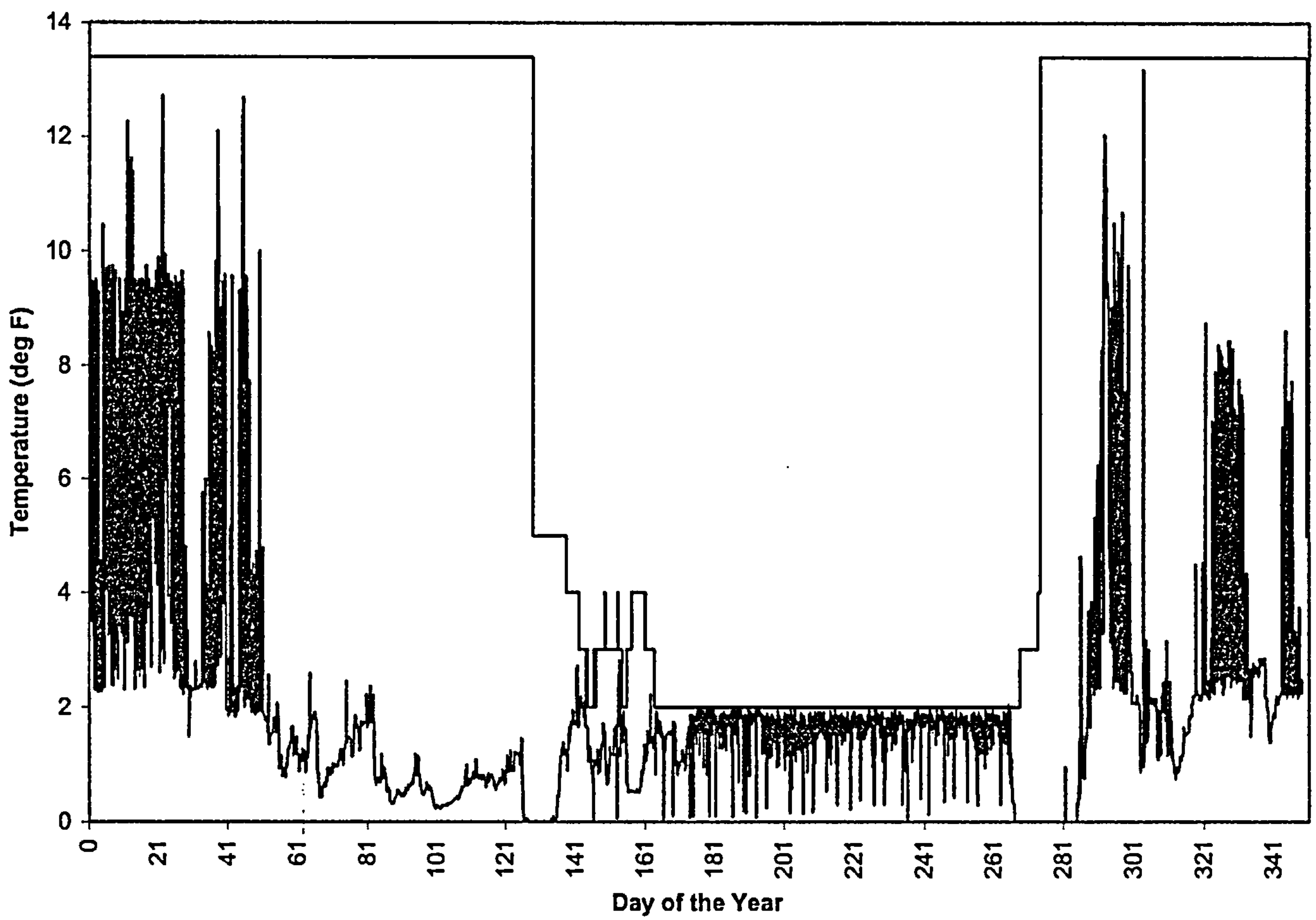

Figure 2-4. Simulated Hourly Connecticut River Temperature Increase at Downstream Monitor 3 During 2002.

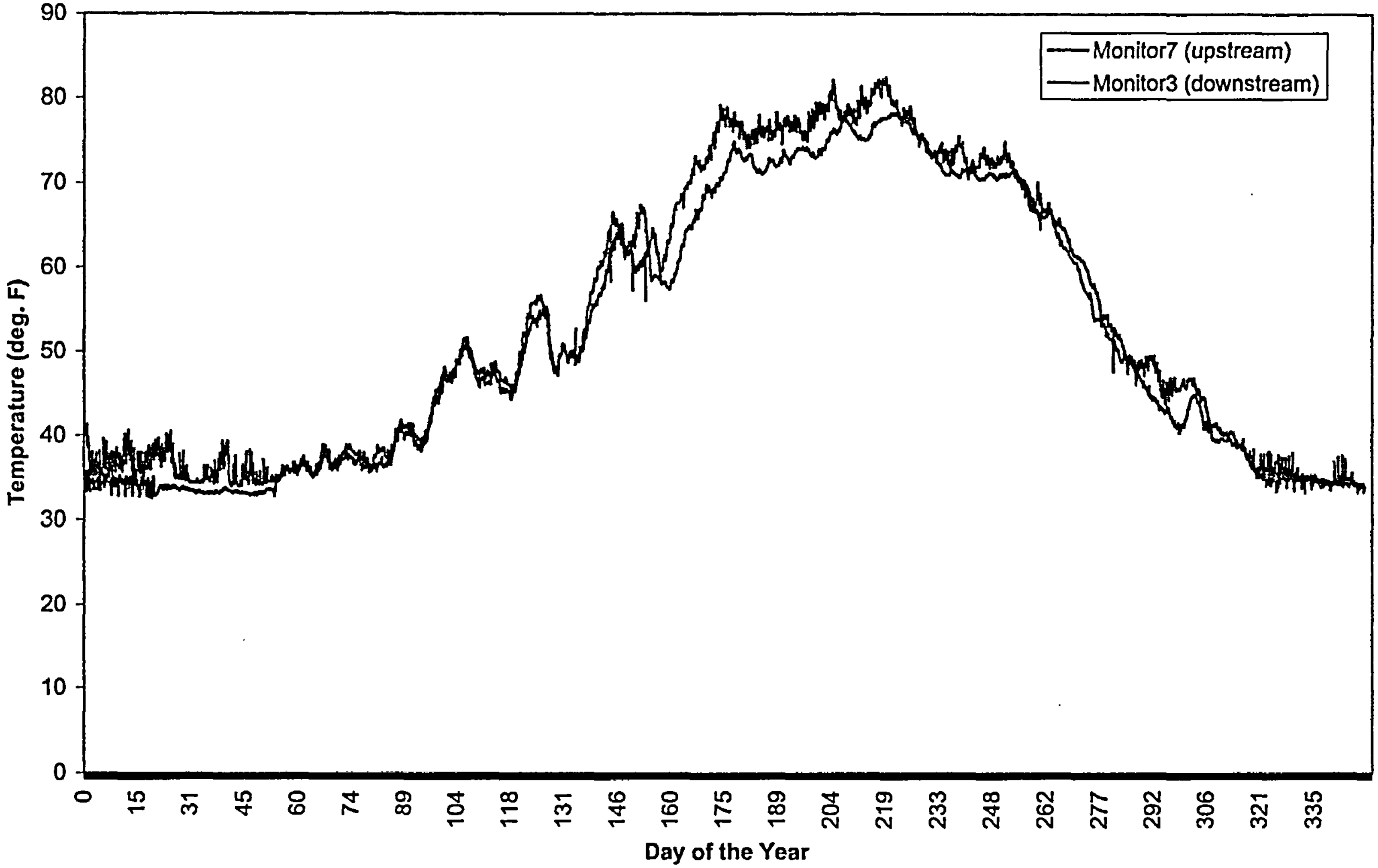

Figure 2-5. Measured Hourly Average Connecticut River Temperatures at Monitoring Stations 3 and 7 During 2002.

Table 2-1. Average Connecticut River Discharge (cfs) at Vernon Station for the Year 2002.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day												
1	2350	7515	12523	35379	19617	12277	10431	4165	2235	1765	4441	7824
2	5474	7120	11702	38023	20305	15722	8694	2861	1533	2733	2936	6721
3	4785	7400	10854	28502	25091	16773	7860	2561	1518	2970	1522	6295
4	5319	5090	15171	30596	21524	13945	7038	3303	1483	2126	2925	6897
5	4269	6217	16582	29984	18854	13470	4447	5345	1534	1697	3517	5306
6	2935	5460	14117	24384	17576	12709	4780	3280	2183	1571	5446	4924
7	4214	5122	9565	21784	16049	21595	4174	1585	1515	2385	4503	3588
8	3357	2968	8355	15646	16965	13735	5669	1964	1518	1789	3559	5925
9	3032	3235	9380	14485	13180	11158	6793	2163	1464	1602	3561	5314
10	3121	2360	16957	22430	13431	7781	7344	1871	1479	2611	3937	4908
11	3068	7325	34035	29487	11907	8156	5341	1375	1464	3074	7801	4958
12	2595	6354	26859	24285	11099	10184	3905	2371	1392	2204	8171	5240
13	2223	6840	21033	25361	14183	31151	3697	3882	1431	2357	13721	4822
14	3609	8632	19260	44530	33849	41475	2693	2426	1368	2989	15314	5981
15	4572	4712	18131	52135	36344	36667	4954	1610	1357	4306	10905	5777
16	3577	5558	17354	59113	28227	30671	4888	2043	1373	4783	7822	8008
17	4280	4488	14256	50611	25972	24084	6005	1509	3706	4856	7941	6815
18	3095	6751	14429	48576	27695	15944	5332	1522	2525	5808	9635	6512
19	2973	7622	12130	43555	29931	12585	4354	1515	2410	5609	11234	6278
20	2460	7767	14057	38634	27461	11025	6480	1519	1722	5885	8807	6108
21	2323	5918	11199	34719	23269	11162	7670	1499	1613	5831	10359	8486
22	2843	7981	10763	28502	22479	8805	7115	1469	1617	5910	10288	11509
23	2727	10772	10194	22033	15808	9672	7206	1474	1978	4454	15626	9352
24	2205	11778	9489	19104	11034	12956	2638	1489	2515	3557	18447	8171
25	2354	10241	8797	20438	11305	10718	2594	2579	2997	2825	15890	7787
26	5088	9546	8755	18377	11389	10589	3622	1925	3083	2596	12611	5751
27	5427	10092	10942	16314	9767	9262	1627	1543	5499	5326	10794	5566
28	5006	13281	15198	18028	9281	17365	2373	2092	3922	7280	9479	5401
29	5740		14903	18069	9383	16057	4831	1967	3283	6421	7908	6291
30	5724		17866	21803	8231	14570	5558	1531	3722	6185	6476	6752
31	7944		28776		8365		3528	2617		4653		6700
Monthly Avg	*3829*	*7077*	*14956*	*29830*	*18373*	*16075*	*5279*	*2228*	*2181*	*3812*	*8519*	*6451*

3.0 WATER QUALITY

3.1 COPPER. IRON AND ZINC CONCENTRATIONS

Beginning in April 1996, and continuing through 2002, monthly grab samples of Connecticut River water from Stations 3, 7, and the plant discharge (Figure 3-1) were analyzed for total copper, iron, and zinc, as outlined in the NPDES permit #3-1199. Results of the analysis are presented in Table 3-1 and Figures 3-2, 3-3 and 3-4. Additionally, as discussed at the EAC meeting in 2002 additional samples were monitored for soluble copper, iron and zinc between November 2002 and May 2003. The soluble metal results for 2002 are included on Table 3-1 and are depicted Figures 3-2a, 3-3a, and 3-4a.

Copper concentrations were observed at or below the detection limit of 0.010 µg/l in nearly all months of 2002 at Connecticut River water sampling Station 7 and in the Vermont Yankee discharge (Table 3-1, Figure 3-2). The highest concentration of copper observed at Station 7 was 0.0087 mg/l on 15 July 2002. The highest concentration of copper observed in the Vermont Yankee Station discharge was 0.0262 mg/l on 16 September 2002. Connecticut River water sampling at Station 3, below the Vernon Dam tailrace, had slightly higher copper concentrations during several months (seven of twelve) in 2002. The highest copper concentration of 0.0592mg/l observed on 15 August 2002 (Table 3-1, Figure 3-2).

Iron concentrations in the Connecticut River water samples were generally less than 0.5mg/L during 2002. The highest iron concentration measured in Vermont Yankee Discharge water was 5.11 mg/L on 16 April 2002. The highest iron concentration of 3.30mg/l was observed at Station 7 on 15 July 2002. The highest iron concentration at Station 3 was 4.27 mg/L on 16 April 2002 (Table 3-1, Figure 3-3).

Zinc concentrations in Connecticut River water samples were generally less than 0.020 mg/l during 2002. (Table 3-1, Figure 3-4). The highest zinc concentration at Station 7 was 0.0303 mg/l observed on 16 December 2002.The highest zinc concentration of 0.2020 mg/l was observed at Station 3 on 16 September 2002. The highest zinc concentration in the Vermont Yankee discharge was 0.0483 mg/l observed on 16 April 2002 (Table 3-1, Figure 3-4).

3.2 WATER TEMPERATURE

Water temperature was measured continuously in the Connecticut River at Station 7 and Station 3 during 2002 and at the Vernon Dam fishway during operation. Daily and monthly average temperature data for Station 7 and Station 3 are summarized in Tables 3-2 and 3-3 and were discussed in Section 2.3; the hourly average temperature data for both stations are plotted on Figure 2-5. Hourly and daily average temperature data from the fishway are presented in Table 3-5 and Figure 3-5. The fishway operated daily from 11 June at 1600 to 18 July 2002 at 0900. During the 2002 period of fishway operation, the hourly water temperature ranged from a low of 58.3°F on 15 June 2002 at 0400 to a high of 80.1°F on 4 July 2002 at 2000.

Calibration of the primary upstream temperature probe linked to the Azonix boxes occurred on 17 April 2002 and the downstream temperature probe was calibrated on 31 May 2002, both calibrations are evident as spikes on Figure 2-5. The spikes occur when the probe has been removed from the river and placed into the calibration equipment.

Several lightning storms cause a modem failure to the Azonix temperature probe system at the downstream Station 3 during summer 2002. Backup temperature data from the WaDaR® data logger was utilized for all occurrences in which Vermont Yankee's primary temperature system was out of service. Back up data was not available for a period in June when the WaDaR malfunctioned causing all data to be lost.

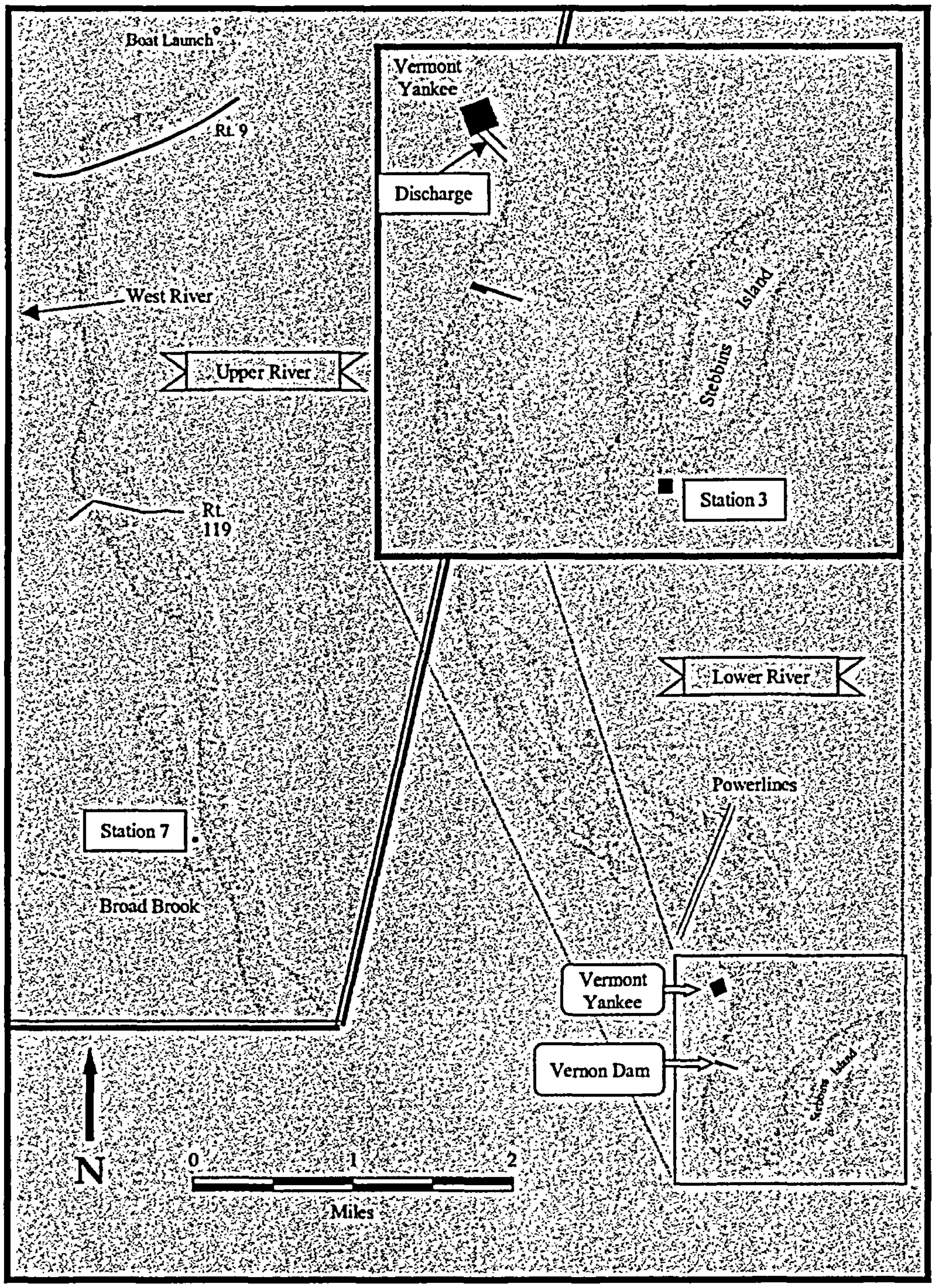

Figure 3-1. NPDES Sampling Stations.

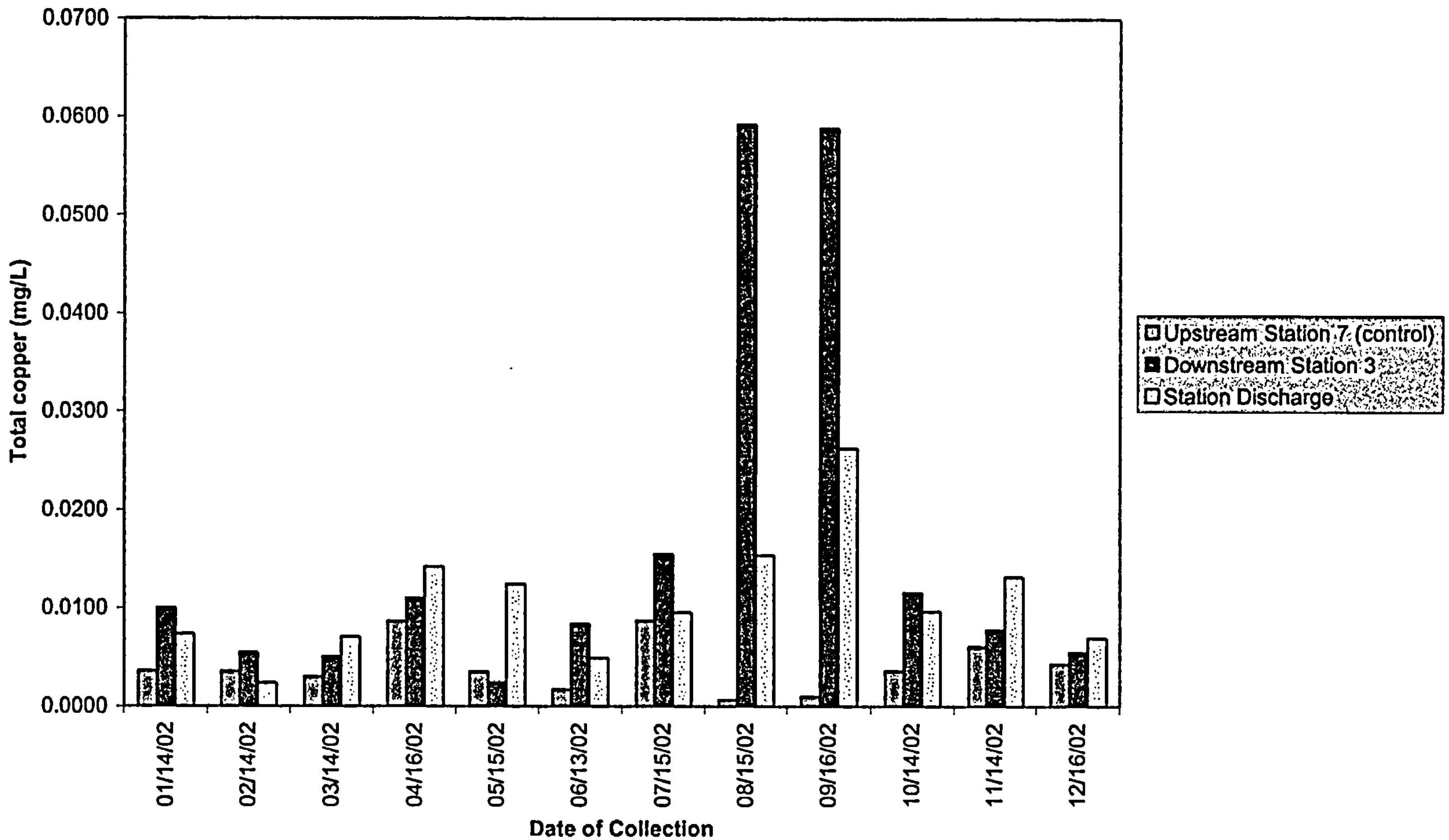

Figure 3-2. Monthly Total Copper Concentrations Observed From the NPDES Permit Required Monitoring Stations.

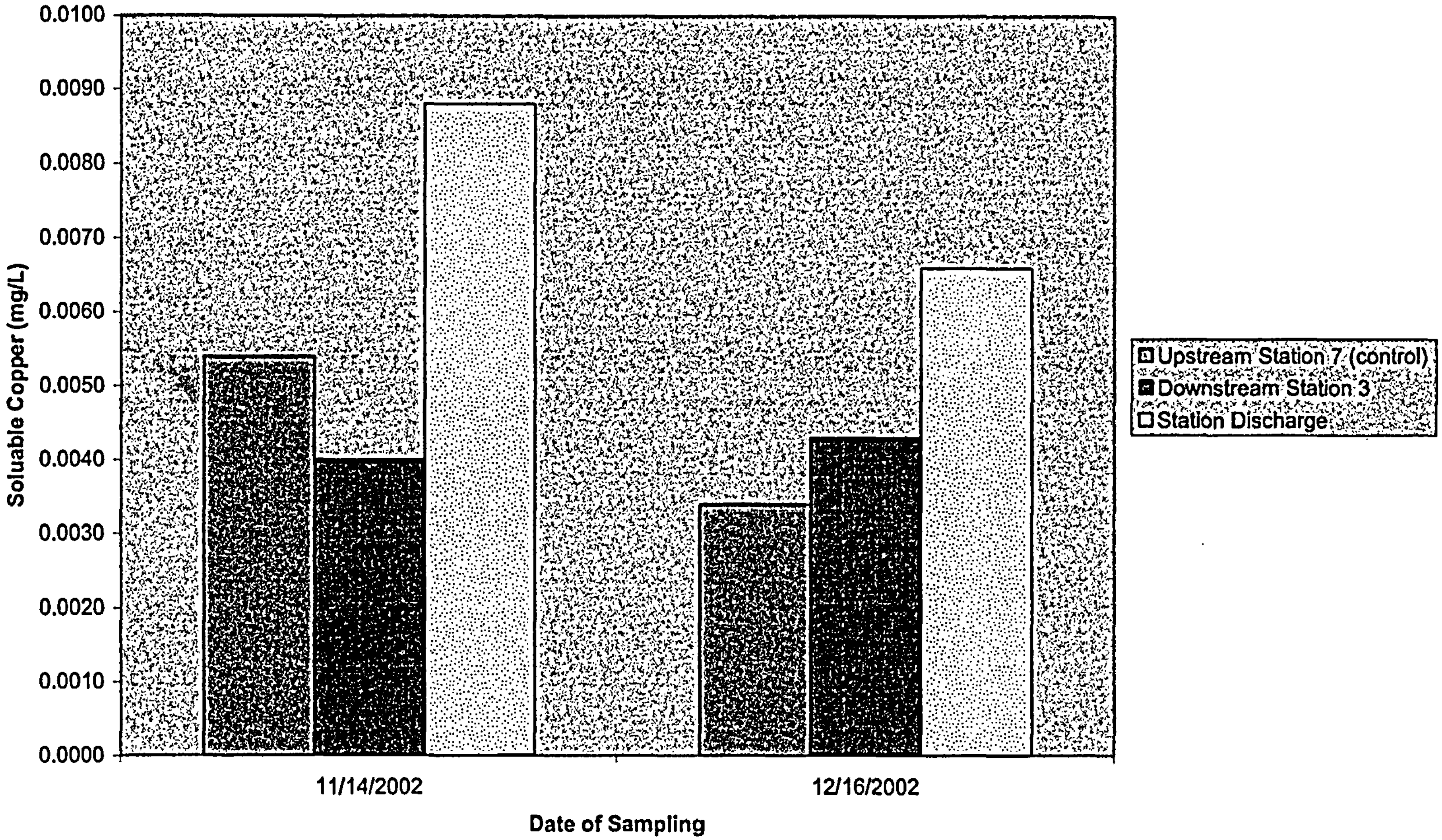

Figure 3-2a. Monthly Soluble Copper Concentrations Observed from the NPDES Permit Required Monitoring Stations.

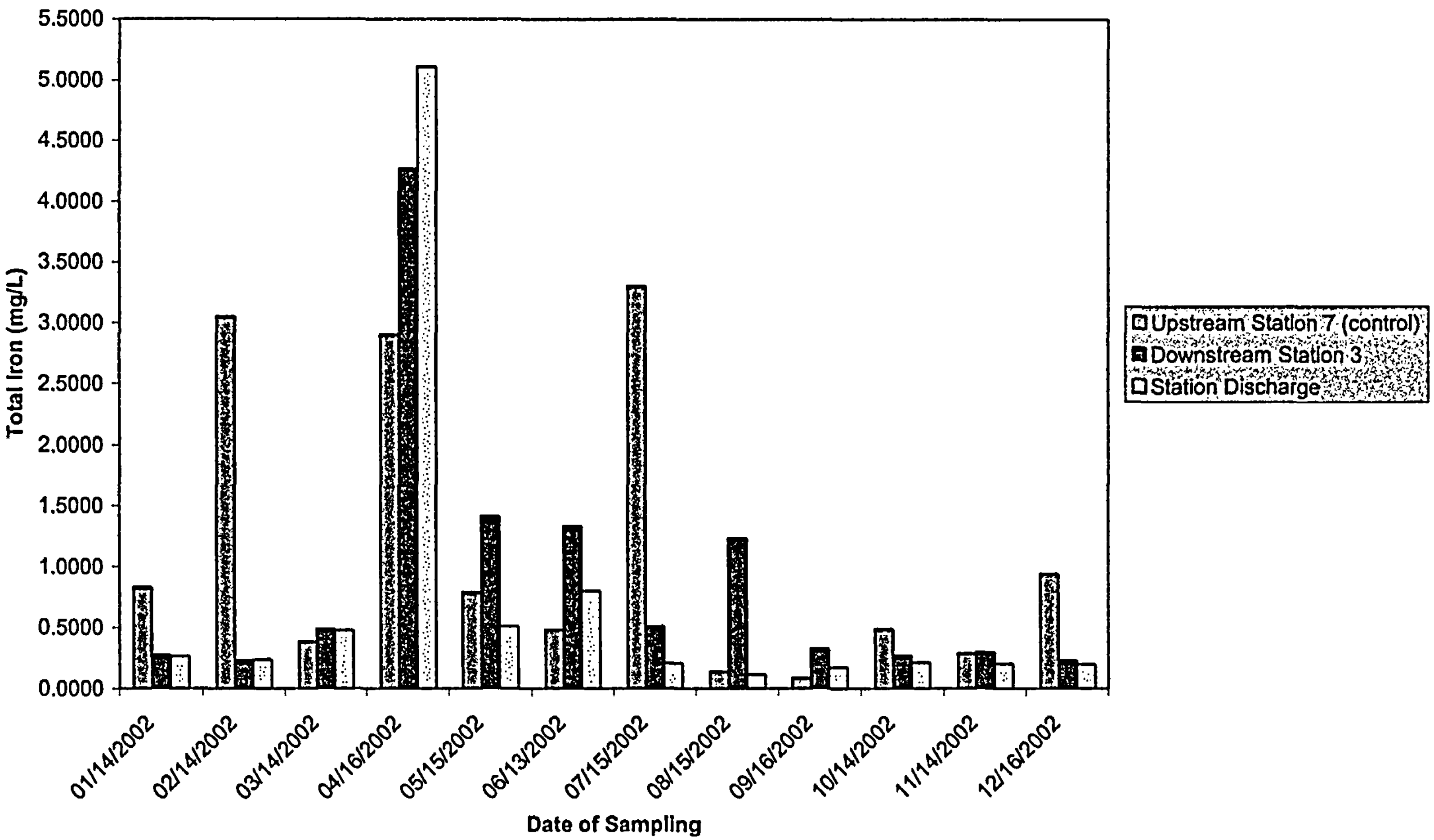

Figure 3-3. Monthly Total Iron Concentrations Observed from the NPDES Permit Required Monitoring Stations.

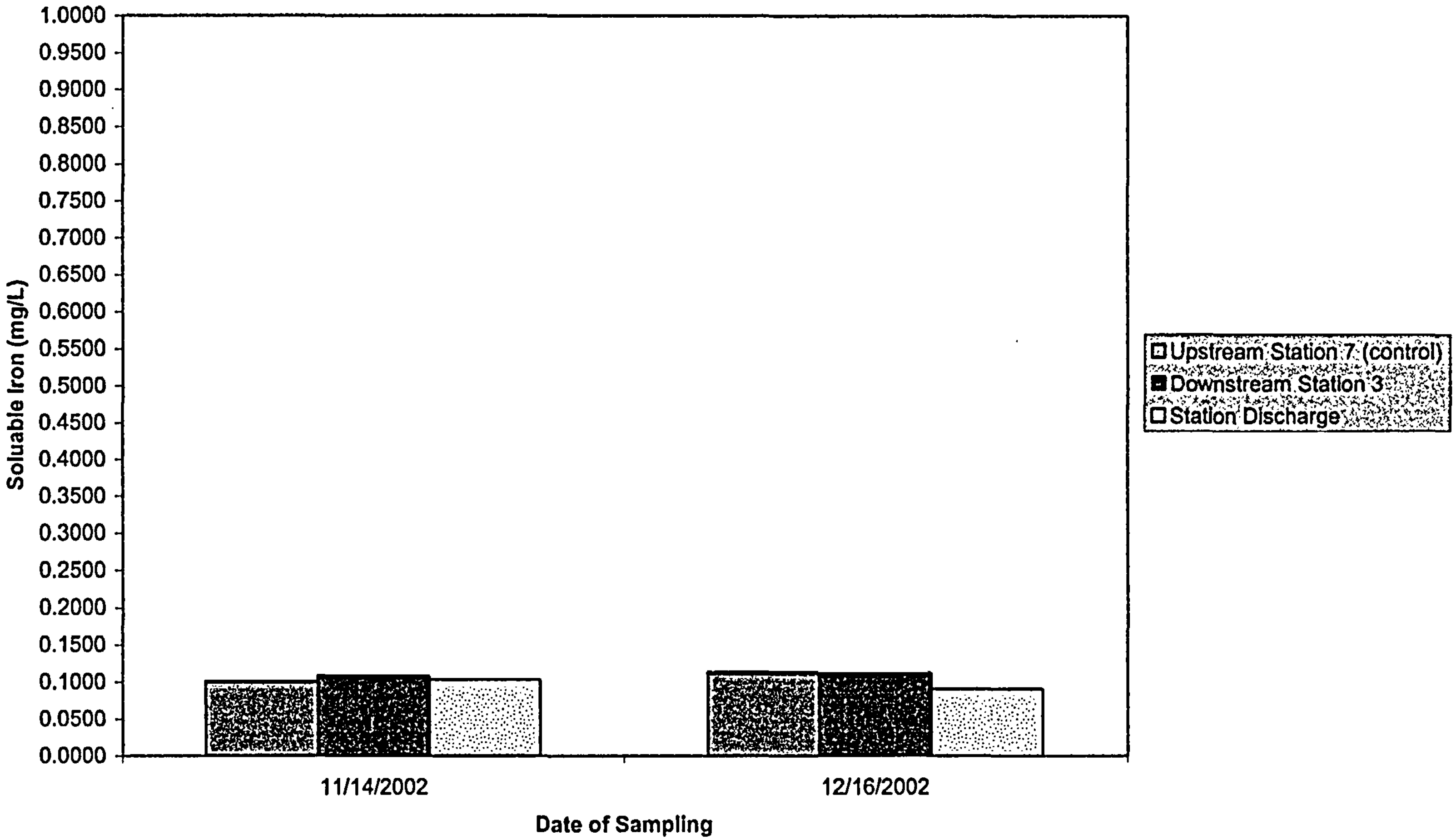

Figure 3-3a. Monthly Soluble Iron Concentrations observed from NPDES Permit Required Connecticut River Monitoring Stations.

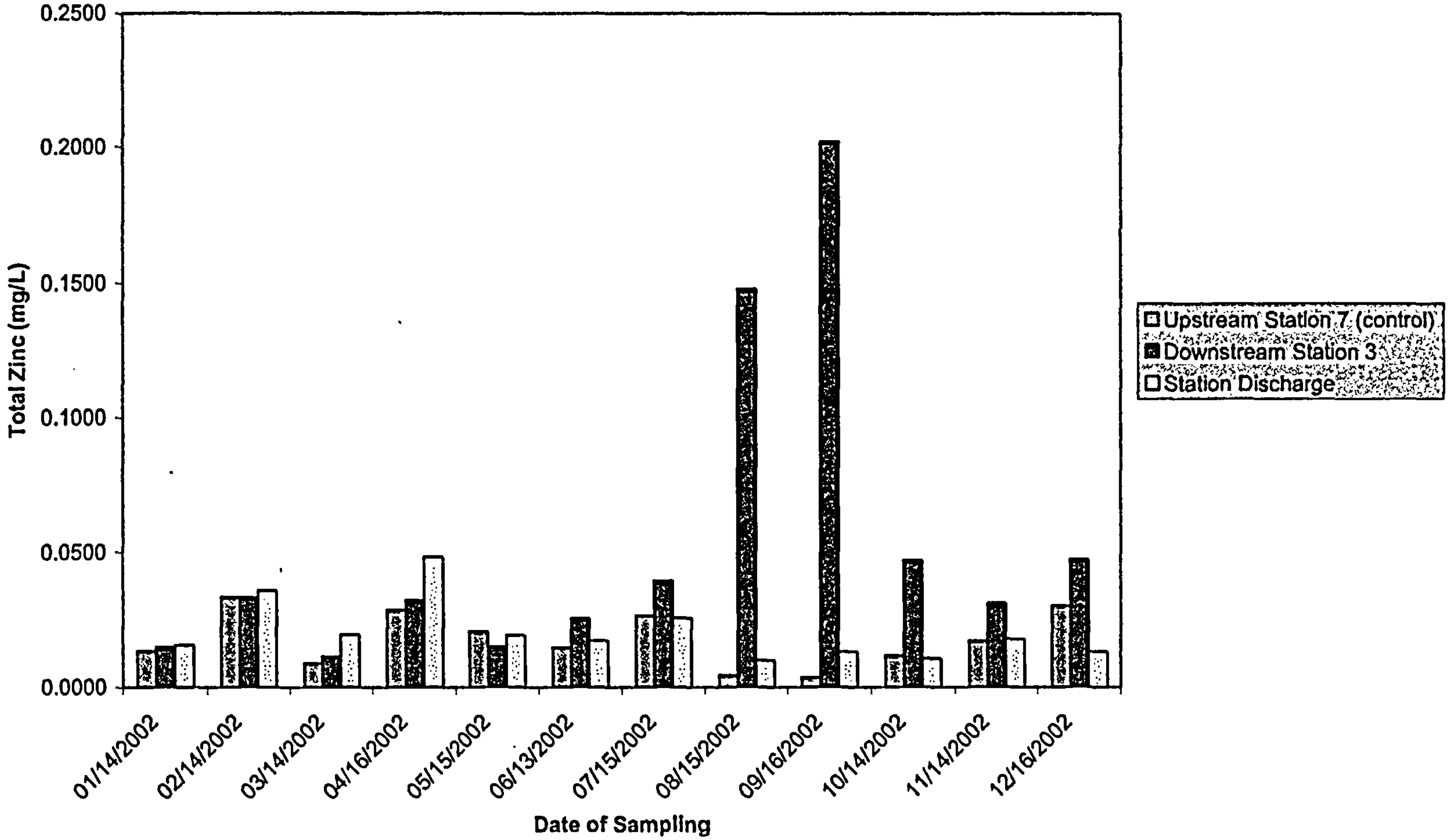

Figure 3-4. Monthly Total Zinc Concentrations Observed at NPDES Permit Required Monitoring Stations.

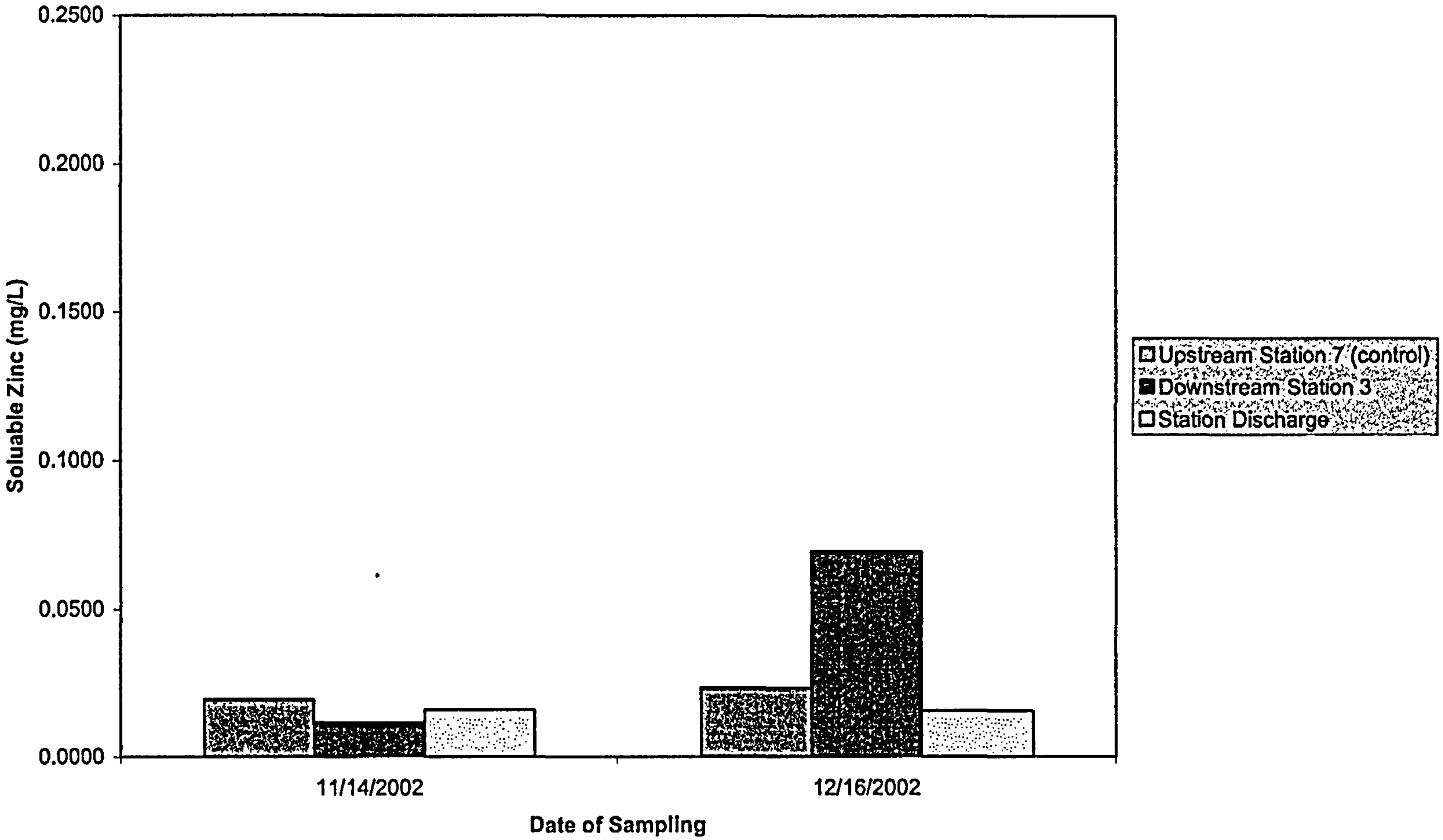

Figure 3-4a. Monthly Soluble Zinc Concentrations Observed from the NPDES Permit Required Monitoring Stations.

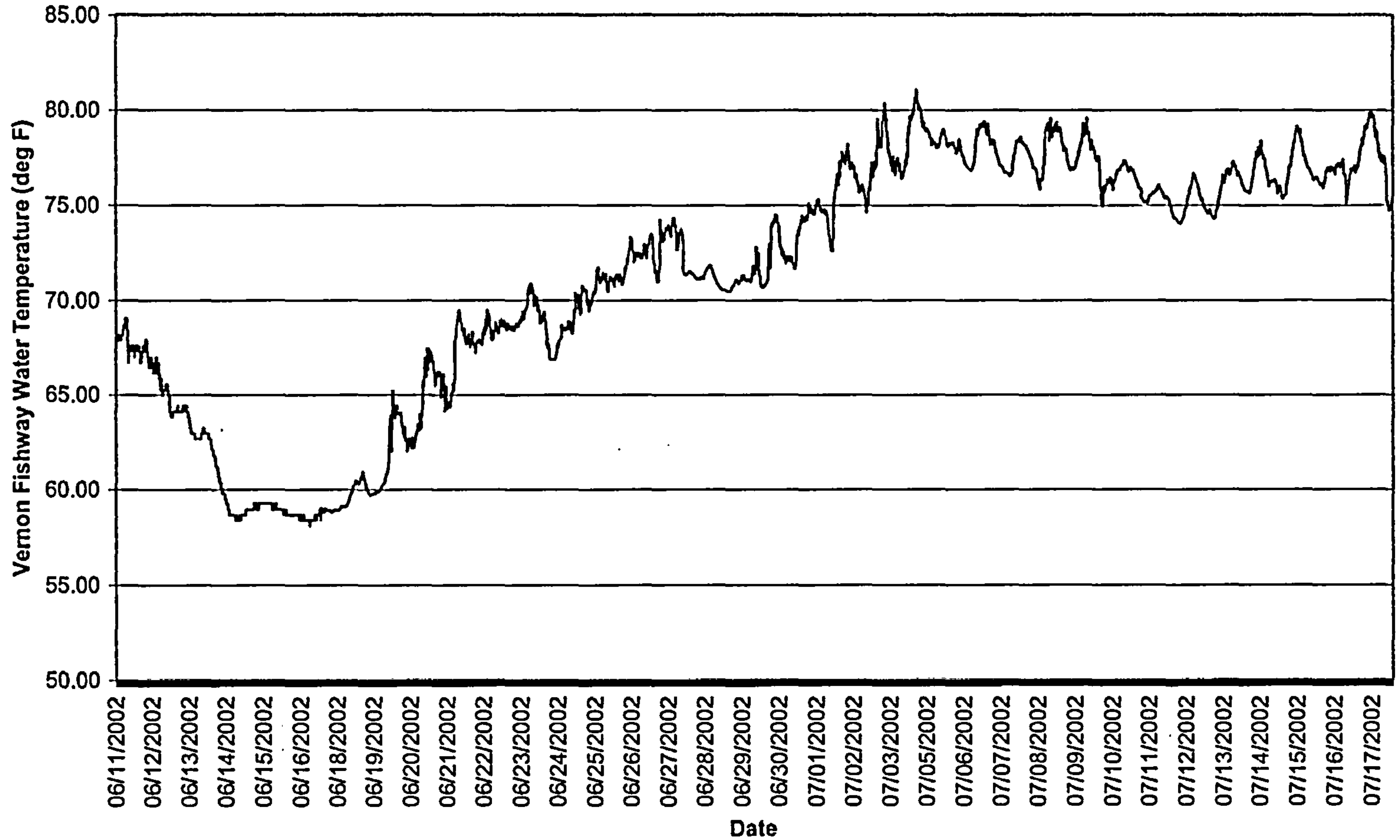

Figure 3-5. Vernon Dam Fishway Water Temperature Data Between 11 June and 18 July 2002.

Table 3-1. 2002 NPDES River Water Metals (mg/L).

Total Metals	Upstream Station 7 (control) *mg/L*			Downstream Station 3 *mg/L*			Station Discharge *mg/L*		
Date	Copper	Iron	Zinc	Copper	Iron	Zinc	Copper	Iron	Zinc
1/14/2002	0.004	0.827	0.014	0.010	0.274	0.015	0.007	0.262	0.016
2/14/2002	0.004	3.050	0.034	0.005	0.228	0.033	0.002	0.234	0.036
3/14/2002	0.003	0.379	0.009	0.005	0.486	0.011	0.007	0.474	0.019
4/16/2002	0.009	2.900	0.029	0.011	4.270	0.032	0.014	5.110	0.048
5/15/2002	0.004	0.786	0.021	0.002	1.410	0.015	0.012	0.510	0.019
6/13/2002	0.002	0.478	0.015	0.008	1.330	0.025	0.005	0.797	0.017
7/15/2002	0.009	3.300	0.027	0.016	0.510	0.040	0.010	0.204	0.026
8/15/2002	0.001	0.136	0.004	0.059	1.230	0.148	0.015	0.114	0.010
9/16/2002	0.001	0.089	0.004	0.059	0.325	0.202	0.026	0.168	0.013
10/14/2002	0.004	0.487	0.012	0.012	0.266	0.047	0.010	0.206	0.011
11/14/2002	0.006	0.285	0.017	0.008	0.294	0.031	0.013	0.201	0.018
12/16/2002	0.004	0.941	0.030	0.006	0.229	0.048	0.007	0.192	0.013

Soluable Metals	Upstream Station 7 (control) *mg/L*			Downstream Station 3 *mg/L*			Station Discharge *mg/L*		
Date	Copper	Iron	Zinc	Copper	Iron	Zinc	Copper	Iron	Zinc
11/14/2002	0.005	0.101	0.020	0.004	0.108	0.012	0.009	0.103	0.016
12/16/2002	0.003	0.113	0.023	0.004	0.112	0.069	0.007	0.091	0.015

Table 3-2. Average Connecticut River Temperature (°F) at Station 7 for the Year 2002.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day												
1	34.5	34.1	33.7	36.9	45.3	52.2	63.2	73.0	76.2	70.4	55.8	41.0
2	35.0	34.1	33.7	37.0	45.4	52.8	63.4	73.1	76.1	70.2	55.1	40.8
3	34.5	34.0	33.8	37.2	45.6	53.4	63.7	73.3	75.9	70.1	54.3	40.5
4	35.0	34.0	33.9	37.3	45.8	53.9	64.0	73.4	75.7	69.9	53.6	40.2
5	34.6	33.9	34.0	37.4	46.0	54.4	64.4	73.5	75.5	69.7	52.9	40.0
6	34.9	33.9	34.1	37.5	46.3	54.8	64.8	73.6	75.3	69.5	52.2	39.7
7	34.9	33.8	34.2	37.6	46.7	55.0	65.2	73.7	75.1	69.3	51.4	39.4
8	34.2	33.8	34.2	37.7	47.2	55.3	65.7	73.8	75.0	69.0	50.7	39.2
9	34.6	33.7	34.4	37.8	47.7	55.5	66.1	73.9	74.9	68.7	50.0	39.1
10	34.1	33.7	34.5	38.0	48.1	55.7	66.5	74.0	74.8	68.4	49.4	38.9
11	34.7	33.7	34.6	38.2	48.5	56.0	66.8	74.1	74.7	68.0	48.8	38.7
12	34.1	33.7	34.7	38.5	48.8	56.3	67.1	74.2	74.5	67.7	48.3	38.4
13	34.6	33.6	34.8	38.8	49.1	56.6	67.3	74.4	74.3	67.3	47.8	38.1
14	34.2	33.6	34.9	39.1	49.2	57.0	67.6	74.5	74.1	66.9	47.4	37.8
15	34.5	33.5	35.0	39.4	49.2	57.3	68.0	74.7	73.9	66.5	47.0	37.5
16	33.9	33.5	35.2	39.7	49.3	57.6	68.5	74.9	73.7	66.1	46.5	37.2
17	34.4	33.5	35.3	40.4	49.3	57.9	69.0	75.0	73.5	65.5	46.1	36.9
18	34.0	33.4	35.4	41.0	49.0	58.2	69.4	75.2	73.2	65.0	45.7	36.7
19	33.8	33.4	35.6	41.4	48.9	58.5	69.9	75.4	73.0	64.4	45.2	36.5
20	33.9	33.4	35.7	41.8	48.9	58.9	70.3	75.5	72.8	63.9	44.8	36.3
21	33.2	33.4	35.8	42.2	48.8	59.4	70.7	75.7	72.5	63.3	44.4	36.2
22	33.6	33.4	35.9	42.6	48.8	59.9	71.0	75.9	72.3	62.6	44.0	36.0
23	33.8	33.4	36.0	43.0	48.9	60.3	71.3	76.0	72.1	62.0	43.6	35.8
24	33.8	33.4	36.1	43.3	49.1	60.7	71.6	76.1	71.9	61.3	43.2	35.7
25	33.8	33.4	36.2	43.6	49.3	61.1	71.8	76.1	71.8	60.6	42.9	35.5
26	33.9	33.5	36.3	44.0	49.6	61.5	72.1	76.2	71.6	59.9	42.6	35.4
27	33.8	33.5	36.4	44.3	50.0	61.9	72.2	76.3	71.4	59.1	42.3	35.2
28	33.6	33.6	36.4	44.6	50.3	62.3	72.4	76.3	71.1	58.4	42.0	35.1
29	33.7		36.5	44.9	50.6	62.7	72.5	76.4	70.9	57.7	41.7	35.0
30	33.6		36.6	45.1	51.1	62.9	72.7	76.3	70.7	57.1	41.3	34.9
31	34.2		36.7		51.6			76.3		56.5		34.8
Monthly Avg	*34.2*	*33.6*	*35.2*	*40.3*	*48.5*	*57.7*	*68.3*	*74.9*	*73.6*	*65.0*	*47.4*	*37.5*

Table 3-3. Average Connecticut River Temperature (°F) at Station 3 for the Year 2002.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day												
1	34.5	34.1	33.7	36.9	45.3	52.2	63.2	73.0	76.2	70.4	55.8	41.0
2	35.0	34.1	33.7	37.0	45.4	52.8	63.4	73.1	76.1	70.2	55.1	40.8
3	34.5	34.0	33.8	37.2	45.6	53.4	63.7	73.3	75.9	70.1	54.3	40.5
4	35.0	34.0	33.9	37.3	45.8	53.9	64.0	73.4	75.7	69.9	53.6	40.2
5	34.6	33.9	34.0	37.4	46.0	54.4	64.4	73.5	75.5	69.7	52.9	40.0
6	34.9	33.9	34.1	37.5	46.3	54.8	64.8	73.6	75.3	69.5	52.2	39.7
7	34.9	33.8	34.2	37.6	46.7	55.0	65.2	73.7	75.1	69.3	51.4	39.4
8	34.2	33.8	34.2	37.7	47.2	55.3	65.7	73.8	75.0	69.0	50.7	39.2
9	34.6	33.7	34.4	37.8	47.7	55.5	66.1	73.9	74.9	68.7	50.0	39.1
10	34.1	33.7	34.5	38.0	48.1	55.7	66.5	74.0	74.8	68.4	49.4	38.9
11	34.7	33.7	34.6	38.2	48.5	56.0	66.8	74.1	74.7	68.0	48.8	38.7
12	34.1	33.7	34.7	38.5	48.8	56.3	67.1	74.2	74.5	67.7	48.3	38.4
13	34.6	33.6	34.8	38.8	49.1	56.6	67.3	74.4	74.3	67.3	47.8	38.1
14	34.2	33.6	34.9	39.1	49.2	57.0	67.6	74.5	74.1	66.9	47.4	37.8
15	34.5	33.5	35.0	39.4	49.2	57.3	68.0	74.7	73.9	66.5	47.0	37.5
16	33.9	33.5	35.2	39.7	49.3	57.6	68.5	74.9	73.7	66.1	46.5	37.2
17	34.4	33.5	35.3	40.4	49.3	57.9	69.0	75.0	73.5	65.5	46.1	36.9
18	34.0	33.4	35.4	41.0	49.0	58.2	69.4	75.2	73.2	65.0	45.7	36.7
19	33.8	33.4	35.6	41.4	48.9	58.5	69.9	75.4	73.0	64.4	45.2	36.5
20	33.9	33.4	35.7	41.8	48.9	58.9	70.3	75.5	72.8	63.9	44.8	36.3
21	33.2	33.4	35.8	42.2	48.8	59.4	70.7	75.7	72.5	63.3	44.4	36.2
22	33.6	33.4	35.9	42.6	48.8	59.9	71.0	75.9	72.3	62.6	44.0	36.0
23	33.8	33.4	36.0	43.0	48.9	60.3	71.3	76.0	72.1	62.0	43.6	35.8
24	33.8	33.4	36.1	43.3	49.1	60.7	71.6	76.1	71.9	61.3	43.2	35.7
25	33.8	33.4	36.2	43.6	49.3	61.1	71.8	76.1	71.8	60.6	42.9	35.5
26	33.9	33.5	36.3	44.0	49.6	61.5	72.1	76.2	71.6	59.9	42.6	35.4
27	33.8	33.5	36.4	44.3	50.0	61.9	72.2	76.3	71.4	59.1	42.3	35.2
28	33.6	33.6	36.4	44.6	50.3	62.3	72.4	76.3	71.1	58.4	42.0	35.1
29	33.7		36.5	44.9	50.6	62.7	72.5	76.4	70.9	57.7	41.7	35.0
30	33.6		36.6	45.1	51.1	62.9	72.7	76.3	70.7	57.1	41.3	34.9
31	34.2		36.7		51.6			76.3		56.5		34.8
Monthly Avg	*34.2*	*33.6*	*35.2*	*40.3*	*48.5*	*57.7*	*68.3*	*74.9*	*73.6*	*65.0*	*47.4*	*37.5*

Table 3-4. Average Heat Rejected by the Condenser (mWt) for the Year 2002.

Month Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1039	1039	679	952	952	1042	744	1067	1054	985	1044	1042
2	1045	1043	952	893	951	1046	991	1064	1054	989	1046	1042
3	1041	1043	1015	951	953	1045	1052	1067	1052	989	1041	1043
4	1043	1045	941	953	953	1043	1054	1065	1057	976	1040	1042
5	1041	1042	1045	951	951	827	1057	1060	1062	970	1043	1042
6	1043	1041	1037	951	950	1036	1058	1064	1058	109	1042	1043
7	1043	1042	636	953	952	1045	1053	1060	1057	0	1041	1043
8	1042	1042	795	844	955	1044	1055	1056	1060	0	1042	1044
9	1042	1041	980	951	952	1046	1052	910	1060	0	1043	1040
10	1038	1041	1017	951	950	1046	1052	1059	1062	0	1044	1040
11	1043	1045	908	953	956	1046	1053	1064	1056	0	1043	1045
12	1043	1043	1038	952	0	1045	1055	1071	1049	0	1042	1043
13	1042	1041	1043	951	0	1047	1056	1067	1051	0	1045	1042
14	1040	1041	1044	950	0	1044	1057	1070	1048	0	1043	1043
15	1041	1042	1044	620	0	1044	1061	1071	1052	0	1041	1043
16	1040	1042	1045	948	0	1044	1061	1070	1047	0	1043	1040
17	1042	1044	1044	951	0	1043	1054	1068	1035	0	1040	1041
18	1042	1043	1044	951	0	1041	1054	1069	1034	0	1042	1043
19	1042	972	1041	949	0	1046	1061	1073	1030	0	1041	1040
20	1042	1042	1041	949	0	1043	1053	1060	1028	0	999	1041
21	1042	1042	1045	952	0	1045	1053	1062	1028	0	1040	1040
22	1040	1043	951	951	0	1048	1053	1061	1032	0	1039	1041
23	1041	1043	951	952	0	1047	1054	1066	1027	0	1042	1042
24	1041	1040	951	951	376	1046	1059	1064	1007	0	1041	1041
25	1042	1044	950	950	790	1048	1061	1058	1009	0	1041	1040
26	1043	1042	951	948	979	1050	1059	1061	1006	0	1044	1040
27	1039	927	951	952	851	1049	1058	1062	999	338	1042	1042
28	1043	634	590	951	1040	1048	1066	1062	994	262	1041	1040
29	1043		662	949	1045	1049	1070	1061	992	795	1041	1041
30	1038		824	954	1044	1048	1055	1061	986	1039	1042	1041
31	1045		947		1044		1066	1060		992		1043
Monthly Avg	*1042*	*1021*	*941*	*935*	*569*	*1038*	*1045*	*1059*	*1036*	*272*	*1041*	*1042*

Table 3-5. Hourly and Daily Average Temperature at (°F) the Vernon Dam Fishway During 2002.

Day	11-Jun	12-Jun	13-Jun	14-Jun	15-Jun	16-Jun	17-Jun	18-Jun	19-Jun	20-Jun	21-Jun	22-Jun
Hour												
0		67.2	65.1	62.7	58.7	59.2	58.5	58.9	60.2	63.6	66.2	67.9
1		67.5	65.2	62.7	58.7	59.2	58.4	58.9	60.1	63.3	66.0	67.8
2		67.4	65.5	62.7	58.6	59.2	58.4	58.9	59.9	63.1	65.9	67.8
3		67.5	65.4	62.9	58.4	59.2	58.4	58.9	59.9	62.9	65.6	67.8
4		67.3	64.7	63.1	58.4	58.9	58.5	59.0	59.8	62.7	65.5	67.7
5		67.4	64.2	63.0	58.5	58.9	58.2	59.0	59.8	62.6	65.4	67.8
6		67.3	63.8	62.9	58.5	59.0	58.4	59.0	59.8	62.5	65.1	67.8
7		67.4	64.7	62.8	58.6	59.1	58.4	59.0	59.9	62.5	65.0	67.8
8		67.1	64.1	62.7	58.7	58.9	58.4	59.1	59.9	62.5	65.0	68.0
9		67.1	64.1	62.6	58.7	58.9	58.6	59.2	60.0	62.7	64.9	68.2
10		67.2	64.2	62.2	58.9	58.9	58.6	59.3	60.1	62.9	65.1	68.4
11		67.5	64.1	61.9	58.9	58.8	58.7	59.4	60.3	63.1	65.6	68.5
12		67.5	64.1	61.6	58.9	58.7	58.5	59.5	60.6	63.5	66.1	68.5
13		67.7	64.1	61.2	58.9	58.8	58.6	59.7	61.0	64.0	66.7	68.6
14		66.8	64.2	60.9	58.9	58.7	58.6	59.9	61.4	64.4	67.3	68.6
15		67.2	64.2	61.7	58.9	58.8	58.7	60.0	62.0	64.9	67.7	68.6
16	67.8	66.8	64.4	60.2	59.2	58.7	58.8	60.2	62.4	65.4	68.1	68.6
17	68.1	66.5	64.1	59.9	59.2	58.7	58.8	60.3	62.9	65.9	68.5	68.5
18	68.1	66.4	63.7	59.8	59.2	58.7	58.8	60.4	63.3	66.2	68.6	68.4
19	68.0	66.3	63.4	59.6	59.2	58.7	58.9	60.5	63.7	66.5	68.5	68.5
20	68.3	66.7	63.0	59.2	59.2	58.7	58.9	60.5	63.9	66.6	68.4	68.5
21	68.7	66.3	62.9	59.1	59.2	58.7	58.9	60.4	63.9	66.5	68.2	68.6
22	69.0	65.8	62.8	58.8	59.2	58.6	58.9	60.3	63.9	66.5	68.0	68.6
23	68.3	66.3	63.4	59.4	59.2	58.6	58.9	60.3	63.7	66.4	68.0	68.6
Daily Average	*68.3*	*67.0*	*64.1*	*61.4*	*58.9*	*58.9*	*58.6*	59.6	61.4	64.2	66.6	68.3

(continued)

Table 3-5. (Continued)

Day	23-Jun	24-Jun	25-Jun	26-Jun	27-Jun	28-Jun	29-Jun	30-Jun	1-Jul	2-Jul	3-Jul	4-Jul
Hour												
0	68.6	69.4	69.3	71.0	72.5	73.5	71.4	71.1	72.8	74.8	77.0	78.5
1	68.6	69.3	69.4	71.0	72.6	73.1	71.3	71.2	72.6	74.8	76.8	78.4
2	68.6	69.0	69.7	71.0	72.8	72.8	71.2	71.2	72.3	74.8	76.5	78.0
3	68.6	68.7	70.0	71.0	72.9	72.5	71.0	71.4	72.2	74.8	76.4	77.7
4	68.6	68.4	70.2	71.1	72.8	72.4	70.9	71.6	72.2	74.7	76.3	77.4
5	68.6	68.1	70.2	71.1	72.7	72.2	70.8	71.6	72.1	74.5	76.1	77.2
6	68.6	67.9	70.2	71.1	72.5	71.9	70.7	71.6	72.1	74.2	75.9	77.1
7	68.6	67.6	70.1	71.1	72.3	71.6	70.6	71.6	72.2	74.0	75.7	77.0
8	68.7	67.3	70.1	71.2	72.3	71.4	70.6	71.5	72.4	74.0	75.6	76.9
9	68.8	67.2	70.2	71.3	72.3	71.4	70.5	71.4	72.6	74.1	75.6	76.9
10	68.8	67.2	70.1	71.4	72.3	71.3	70.5	71.3	72.9	74.4	75.8	77.0
11	69.0	67.2	70.1	71.6	72.3	71.3	70.5	71.2	73.2	74.6	75.9	77.1
12	69.1	67.4	70.2	71.9	72.6	71.3	70.6	71.2	73.5	75.0	76.0	77.3
13	69.3	67.6	70.4	72.1	72.8	71.2	70.7	71.4	73.8	75.5	76.2	77.6
14	69.6	67.8	70.5	72.2	73.2	71.2	70.7	71.8	74.0	76.1	76.7	78.0
15	69.8	68.0	70.7	72.4	73.5	71.2	70.8	72.2	74.2	76.6	77.2	78.4
16	70.0	68.2	70.9	72.5	73.6	71.2	70.9	72.7	74.3	77.0	77.5	78.9
17	70.1	68.3	71.0	72.5	73.6	71.3	70.9	73.1	74.4	77.2	77.8	79.4
18	70.2	68.4	71.1	72.5	73.7	71.4	71.0	73.5	74.5	77.4	78.1	79.7
19	70.3	68.5	71.2	72.5	73.8	71.4	71.1	73.6	74.5	77.4	78.5	80.0
20	70.2	68.5	71.1	72.4	73.6	71.5	71.1	73.6	74.6	77.4	78.8	80.1
21	70.0	68.7	71.1	72.4	73.6	71.5	71.1	73.6	74.7	77.4	79.0	80.1
22	69.8	68.9	71.1	72.4	73.5	71.5	71.1	73.3	74.8	77.3	78.8	80.0
23	69.6	69.1	71.0	72.5	73.5	71.5	71.1	73.1	74.8	77.2	78.7	79.9
Daily Average	*69.3*	*68.2*	*70.4*	*71.8*	*73.0*	*71.7*	*70.9*	*72.1*	*73.4*	*75.6*	*77.0*	*78.3*

(continued)

Table 3-5. (Continued)

Day	5-Jul	6-Jul	7-Jul	8-Jul	9-Jul	10-Jul	11-Jul	12-Jul	13-Jul	14-Jul	15-Jul	16-Jul
Hour												
0	79.7	78.1	78.5	78.0	78.6	77.4	76.8	75.4	75.6	76.8	76.5	77.8
1	79.5	78.0	78.3	77.9	78.4	77.0	76.7	75.3	75.4	76.8	76.3	77.5
2	79.3	77.9	78.2	77.7	78.1	76.7	76.6	75.1	75.2	76.7	76.2	77.2
3	79.1	77.8	77.9	77.5	77.9	76.5	76.4	75.0	75.0	76.5	76.1	77.0
4	78.9	77.6	77.7	77.4	77.6	76.3	76.3	74.8	74.9	76.3	76.1	76.8
5	78.8	77.5	77.6	77.1	77.4	76.1	76.1	74.7	74.8	76.2	76.0	76.7
6	78.6	77.4	77.4	76.9	77.2	76.0	75.9	74.5	74.6	76.1	75.9	76.5
7	78.5	77.2	77.2	76.7	77.1	75.9	75.7	74.4	74.5	75.9	75.8	76.4
8	78.4	77.1	77.0	76.6	77.1	75.9	75.5	74.3	74.5	75.9	75.7	76.3
9	78.3	77.0	76.9	76.5	77.1	76.1	75.4	74.2	74.6	75.9	75.8	76.3
10	78.3	77.1	76.8	76.7	77.3	76.2	75.4	74.3	74.7	76.0	75.9	76.2
11	78.3	77.3	76.7	77.0	77.5	76.3	75.3	74.3	74.8	76.2	76.1	76.3
12	78.4	77.5	76.8	77.3	77.7	76.4	75.4	74.5	75.1	76.5	76.3	76.3
13	78.4	77.8	76.9	77.6	77.9	76.5	75.4	74.7	75.3	76.7	76.6	76.4
14	78.5	78.1	77.1	78.0	78.2	76.6	75.5	74.9	75.6	77.0	77.0	76.4
15	78.5	78.4	77.3	78.4	78.5	76.7	75.6	75.2	75.9	77.3	77.5	76.6
16	78.5	78.7	77.5	78.7	78.6	76.8	75.7	75.5	76.1	77.5	77.8	76.6
17	78.5	79.0	77.7	78.9	78.6	76.9	75.7	75.7	76.3	77.6	78.1	76.8
18	78.4	79.1	77.9	79.1	78.6	77.0	75.8	75.9	76.5	77.6	78.4	76.8
19	78.4	79.1	78.1	79.0	78.6	77.0	75.8	76.1	76.7	77.5	78.5	76.9
20	78.3	79.0	78.2	79.0	78.4	77.0	75.7	76.1	76.8	77.3	78.5	76.9
21	78.1	78.9	78.3	79.0	78.3	77.0	75.7	76.1	76.8	77.1	78.5	77.0
22	78.1	78.8	78.2	78.8	78.0	77.0	75.6	76.0	76.9	76.9	78.3	77.0
23	78.1	78.7	78.2	78.7	77.8	76.9	75.6	75.8	76.9	76.6	78.0	77.0
Daily Average	*78.6*	*78.1*	*77.6*	*77.9*	*77.9*	*76.6*	*75.8*	*75.1*	*75.6*	*76.7*	*76.9*	*76.7*

(continued)

Table 3-5. (Continued)

Day	17-Jul	18-Jul
Hour		
0	77.0	79.0
1	76.8	78.7
2	76.7	78.5
3	76.5	78.2
4	76.5	77.9
5	76.5	77.5
6	76.4	77.0
7	76.4	76.6
8	76.4	76.2
9	76.6	76.1
10	76.8	
11	77.1	
12	77.3	
13	77.5	
14	77.7	
15	78.0	
16	78.3	
17	78.7	
18	79.0	
19	79.2	
20	79.3	
21	79.4	
22	79.4	
23	79.2	
Daily Average	*77.6*	*77.6*

4.0 MACROINVERTEBRATE COLLECTIONS

4.1 METHODS OF COLLECTION AND PROCESSING

4.1.1 Dredge Collections

Dredge sampling was discontinued in the current NPDES Permit therefore Entergy Nuclear Vermont Yankee and Normandeau Associates did not conduct this type of sampling for macroinvertebrates during 2002.

4.1.2 Macroinvertebrate Rock Basket Collections

The current NPDES Permit requires the deployment of three rock baskets at downstream stations 227 and 031, with no required rock basket sampling at the upstream stations (Figure 5-1). Rock baskets used in 2002 were made of one-inch square, 14-gauge galvanized wire with a PVC coating. The cylindrical basket measured 6.5 inches in diameter and 11 inches in length. Each rock basket was filled with clean cobble-sized rocks from the Connecticut River prior to sampling. Rock basket sampling was conducted during 2002 as stipulated in the current NPDES Permit.

On 4 June, 1 August and again on 1 October 2002, three rock baskets were deployed each at stations 227 VT and 031 NH. The June, August and October rock baskets sampled for 30 days (Figure 5-1). Station 227 near the Vermont shore is the most downstream rock basket sampling station. The sampling site is approximately 10-12 ft deep with a substrate of cobble, boulders, and mud. Station 031 is a swift-water riffle area approximately 4 to 5 feet in depth consisting of a sandy bottom, on the New Hampshire shore

Upon retrieval, each rock basket sampler was placed into an individual 5 gallon bucket. The rocks were washed onto a number 30 sieve (600µm) and examined for attached organisms in the field. The contents of each rock basket sample were preserved in 70% ethanol for later identification in the laboratory. A total of 18 rock basket samples, three samples from each of two stations for June, August, and October, were collected during 2002.

In the laboratory, the contents of each macroinvertebrate rock basket sample were examined without sub sampling under low magnification (2x) to separate (sort) the organisms from the sediment and detritus. Identification of organisms to the lowest possible taxonomic level, given their life stage and condition, was accomplished using dissecting (45x) and compound (1,000x) microscopes. Chironomids and oligochaetes were separated by subfamily, tribe, or recognizable type prior to identification to the genus/species level. All or representative subsamples from each grouping were prepared by clearing and mounting and identified with a compound microscope. Where sub sampled, the number of specimens identified to genus/species was used to proportion the remaining individuals from each group into specific taxa. In instances where chironomid or oligochaete specimens could be identified to genus or species without the aid of a compound microscope, no preparation was necessary. Taxonomic keys used to identify all specimens in addition to chironomids and oligochaetes, were: Burks (1953), Hitchcock (1974), Burch (1975), McCafferty (1975), Brown (1976), Simpson and Bode (1980), Wiederholm (1983), Klemm (1985), Roback (1985), Brinkhurst (1986), Peckarsky (1990), Jokinen (1992), Merritt and Cummins (1996), Wiggins (1996).

4.2 SUMMARY

During June, August, and October 2002, a total of 18 rock basket samples were collected and processed after sampling at stations 227 and 031. From these samples, 4,198 macroinvertebrates were identified (Table 4-1). In June, August, and October a total of 1,481, 410, and 1,526 macroinvertebrates respectively were collected at Station 031 (Table 4-2). In June, August and October a total of 276, 369, and 136 macroinvertebrates respectively were collected at Station 227 (Table 4-3). Overall 81.4% of the organisms collected were collected at station 031 and 18.6% were collected from station 227.

Rock Basket Collections

During the three 2002 sampling periods, 4,198 macroinvertebrates were collected and identified, and 91% of the total were made up of caddisflies (Tricoptera, 46.0%), true flies (Diptera, 28.4%), and mayflies (Ephemeroptera, 16.3%) (Table 4-1). Overall, more macroinvertebrates were collected at station 031 than at station 227 (Table 4-2 and 4-3).

June 2002 Rock Basket Collections – Stations 227 and 031

The number of benthic macroinvertebrates collected by rock basket during June 2002, was greater at station 031 (1,481) (Table 4-2) than at station 227 (276) (Table 4-3). The upstream station (031) collections were comprised of Trichoptera (49%) and Diptera (48%), which made up 97% of the June 2002 sample. Turbellaria, Ephemeroptera, Plecoptera, and Coleoptera made up the remaining 3% (Table 4-2). Ninety-one percent of the organisms collected from the downstream station (227) consisted of Trichoptera, Diptera, and Ephemeroptera (Table 4-3), 37%, 37%, and 16% respectively.

August 2002 Rock Basket Collections – Stations 227 and 031

A total of 410 and 369 macroinvertebrates were collected at stations 031 and 227, respectively, in the August 2002 rock basket samples. Ephemeropterans, Trichopterans, and Turbellarians contributed 90.0% to the relative abundance at Station 031 (Table 4-2). Ephemeropterans contributed 49% to the relative abundance at Station 227, with an additional 28.0% comprised of Trichopterans and gastropods (Table 4-3).

October 2002 Rock Basket Collections – Stations 227 and 031

During October 2002, macroinvertebrate collections were greater at station 031 than at station 227, 1,526 and 136 respectively. Ninety-four percent of the organisms collected at Station 3 consisted of three taxa; Trichoptera (59%), Diptera (19%), and Ephemeroptera (16%) (Table 4-2). Eighty-one percent of the organisms collected at Station 227 in October were represented by the following three taxa; gastropods (59%), Trichoptera (13%), and Diptera (9.0%) (Table 4-3).

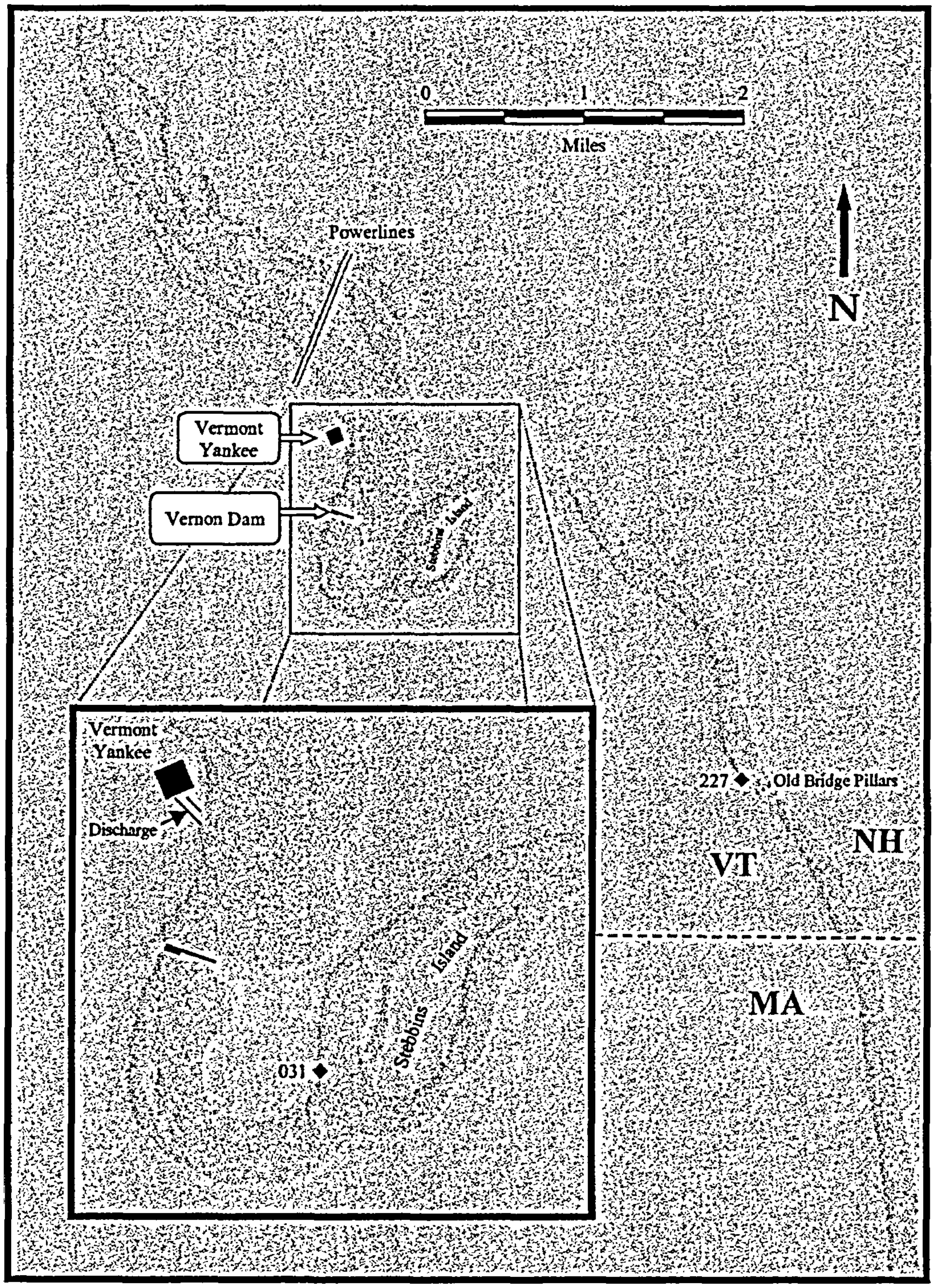

Figure 4-1. NPDES Macroinvertebrate Rock Basket Sampling Stations 227 and 031.

Table 4-1. Total Number, Mean, and Total Percentage of Macroinvertebrates Collected by Rock Basket Samplers at Station 031 and 227 During June, August, and October 2002.

Taxon	Station 31 Count	Station 31 Mean	Station 31 % of Total	Station 227 Count	Station 227 Mean	Station 227 % of Total
PORIFERA	P	P		P	P	
Total	P	P		P	P	
NEMATODA	0	0.0		3	0.3	100.0
Total	0	0.0		3	0.3	100.0
PLATYHELMINTHES						
TURBELLARIA						
Dugesia tigrina	86	9.6	100.0	6	0.7	100.0
Total	86	9.6	100.0	6	0.7	100.0
ANNELIDA						
OLIGOCHAETA						
Limnodrilus sp.	1	0.1	50.0	0	0.0	0.0
Nais communis	0	0.0	0.0	7	0.8	100.0
Stylaria sp.	1	0.1	50.0	0	0.0	0.0
Total	2	0.2	100.0	7	0.8	100.0
MOLLUSCA						
GASTROPODA						
Amnicola sp.	0	0.0	0.0	1	0.1	0.9
Ferrissia sp.	10	1.1	76.9	67	7.4	59.8
Menetus dilatatus	2	0.2	15.4	2	0.2	1.8
Physa sp.	1	0.1	7.7	42	4.7	37.5
Total	13	1.4	100.0	112	12.4	100.0
ARACHNIDA						
ACARINA						
Hydrachnida	3	0.3	100.0	0	0.0	
Total	3	0.3	100.0	0	0.0	
CRUSTACEA						
BRACHIOPODA						
Cladocera	0	0.0		2	0.2	100.0
Total	0	0.0		2	0.2	100.0
CYCLOPOIDA						
Argulus sp.	0	0.0		1	0.1	100.0
Total	0	0.0		1	0.1	100.0
ISOPODA						
Caecidotea sp.	1	0.1	100.0	0	0.0	
Total	1	0.1	100.0	0	0.0	
AMPHIPODA						
Hyalella azteca	3	0.3	100.0	42	4.7	100.0
Total	3	0.3	100.0	42	4.7	100.0
DECAPODA						
Crangonyx sp.	5	0.6	71.4	0	0.0	0.0
Orconectes sp.	2	0.2	28.6	2	0.2	100.0
Total	7	0.8	100.0	2	0.2	100.0

Table 4-1. Continued.

INSECTA						
EPHEMEROPTERA						
Baetis sp.	18	2.0	4.0	2	0.2	0.9
Caenis sp.	0	0.0	0.0	2	0.2	0.9
Ephemerella sp.	1	0.1	0.2	0	0.0	0.0
Eurylophella sp.	4	0.4	0.9	0	0.0	0.0
Isonychia sp.	13	1.4	2.9	2	0.2	0.9
Seratella serratoides	2	0.2	0.4	0	0.0	0.0
Stenacron sp.	17	1.9	3.8	67	7.4	28.9
Stenonema sp.	395	43.9	87.4	158	17.6	68.1
Tricorythodes sp.	2	0.2	0.4	1	0.1	0.4
Total	452	50.1	100.0	232	25.7	100.0
ODONATA						
Argia sp.	1	0.1	33.3	11	1.2	52.4
Boyeria sp.	0	0.0	0.0	1	0.1	4.8
Enallagma sp.	1	0.1	33.3	1	0.1	4.8
Neurocordulia sp.	1	0.1	33.3	8	0.9	38.1
Total	3	0.3	100.0	21	2.3	100.0
PLECOPTERA						
Acroneuria sp.	5	0.6	8.1	2	0.2	100.0
Agnetina sp.	2	0.2	3.2	0	0.0	0.0
Paragnetina sp.	1	0.1	1.6	0	0.0	0.0
Taeniopteryx sp.	54	6.0	87.1	0	0.0	0.0
Total	62	6.9	100.0	2	0.2	100.0
COLEOPTERA						
Ancyronyx sp.	0	0.0	0.0	3	0.3	30.0
Dineutus sp.	8	0.9	61.5	4	0.4	40.0
Macronychus sp.	0	0.0	0.0	1	0.1	10.0
Optioservus sp.	3	0.3	23.1	0	0.0	0.0
Stenelmis sp.	2	0.2	15.4	2	0.2	20.0
Total	13	1.4	100.0	10	1.0	100.0
TRICHOPTERA						
Brachycentrus sp.	2	0.2	0.1	0	0.0	0.0
Ceratopsyche sp.	57	6.3	3.3	1	0.1	0.5
Cernotina sp.	0	0.0	0.0	10	1.1	5.1
Cheumatopsyche sp.	1034	114.9	60.0	65	7.2	33.0
Hydatophylax sp.	0	0.0	0.0	4	0.4	2.0
Hydropsyche sp.	235	26.1	13.6	1	0.1	0.5
Hydroptila sp.	1	0.1	0.1	0	0.0	0.0
Macrostemum carolina	0	0.0	0.0	1	0.1	0.5
Macrostemum sp.	183	20.3	10.6	0	0.0	0.0
Mystacides sp.	1	0.1	0.1	0	0.0	0.0
Neureclipsis sp.	200	22.2	11.6	101	11.2	51.3
Oecetis sp.	6	0.7	0.3	4	0.4	2.0
Polycentropus sp.	3	0.3	0.2	9	1.0	4.6
Triaenodes sp.	0	0.0	0.0	1	0.1	0.5
Total	1722	191.2	100.0	197	21.7	100.0

Table 4-1. Continued.

DIPTERA						
Ablabesmyia sp.	12	1.3	1.1	7	0.8	4.9
Brillia sp.	0	0.0	0.0	1	0.1	0.7
Cardiocladius sp.	14	1.6	1.3	12	1.3	8.3
Cricotopus sp.	40	4.4	3.8	0	0.0	0.0
Dicrotendipes sp.	12	1.3	1.1	12	1.3	8.3
Endochironomus sp.	0	0.0	0.0	1	0.1	0.7
Eukiefferiella sp.	6	0.7	0.6	1	0.1	0.7
Glyptotendipes sp.	7	0.8	0.7	1	0.1	0.7
Nanocladius sp.	0	0.0	0.0	1	0.1	0.7
Orthocladius sp.	24	2.7	2.3	6	0.7	4.2
Parametriocnemus sp.	1	0.1	0.1	0	0.0	0.0
Polypedilum sp.	130	14.4	12.4	17	1.9	11.8
Rheotanytarsus sp.	353	39.2	33.6	81	9.0	56.3
Simulium sp.	416	46.2	39.6	0	0.0	0.0
Stictochironomus sp.	0	0.0	0.0	1	0.1	0.7
Stilocladius sp.	1	0.1	0.1	0	0.0	0.0
Tanytarsus sp.	6	0.7	0.6	3	0.3	2.1
Thienemanniella sp.	2	0.2	0.2	0	0.0	0.0
Thienemannimyia gr.	2	0.2	0.2	0	0.0	0.0
Tvetenia sp.	24	2.7	2.3	0	0.0	0.0
Total	1050	116.6	100.0	144	15.9	100.0
Grand Total (All Taxa)	3417	379.7	100.0	781	86.8	100.0

Table 4-2. Macroinvertebrates Collected by Rock Basket Samplers at Station 031 During June, August, and October 2002.

Taxon	Month								
	June			August			October		
	Count	Mean	% of Total	Count	Mean	% of Total	Count	Mean	% of Total
PORIFERA	0	0.0		P	P		0	0.0	
Total	0	0.0		P	P		0	0.0	
PLATYHELMINTHES									
TURBELLARIA									
Dugesia Tigrina	4	1.3	100.0	82	27.3	100.0	0	0.0	
Total	4	1.3	100.0	82	27.3	100.0	0	0.0	
ANNELIDA									
OLIGOCHAETA									
Limnodrilus sp.	0	0.0		1	0.3	50.0	0	0.0	
Stylaria sp.	0	0.0		1	0.3	50.0	0	0.0	
Total	0	0.0		2	0.6	100.0	0	0.0	
MOLLUSCA									
GASTROPODA									
Ferrissia sp.	0	0.0		0	0.0	0.0	10	3.3	83.3
Menetus Dilatatus	0	0.0		1	0.3	100.0	1	0.3	8.3
Physa sp.	0	0.0		0	0.0	0.0	1	0.3	8.3
Total	0	0.0		1	0.1	100.0	12	3.9	100.0
ARACHNIDA									
ACARINA									
Hydrachnida	0	0.0		1	0.3	100.0	2	0.7	100.0
Total	0	0.0		1	0.3	100.0	2	0.7	100.0
CRUSTACEA									
BRACHIOPODA									
Cladocera	0	0.0		0	0.0		0	0.0	
Total	0	0.0		0	0.0		0	0.0	
ISOPODA									
Caecidotea sp.	0	0.0		1	0.3	100.0	0	0.0	
Total	0	0.0		1	0.3	100.0	0	0.0	
AMPHIPODA									
Hyalella Azteca	0	0.0		0	0.0		3	1.0	100.0
Total	0	0.0		0	0.0		3	1.0	100.0
DECAPODA									
Crangonyx sp.	0	0.0		5	1.7	100.0	0	0.0	0.0
Orconectes sp.	0	0.0		0	0.0	0.0	2	0.7	100.0
Total	0	0.0		5	0.8	100.0	2	0.7	100.0
INSECTA									
EPHEMEROPTERA									
Baetis sp.	18	6.0	64.3	0	0.0	0.0	0	0.0	0.0
Ephemerella sp.	1	0.3	3.6	0	0.0	0.0	0	0.0	0.0
Eurylophella sp.	0	0.0	0.0	0	0.0	0.0	4	1.3	1.6
Isonychia sp.	1	0.3	3.6	0	0.0	0.0	12	4.0	4.8
Seratella Serratoides	2	0.7	7.1	0	0.0	0.0	0	0.0	0.0
Stenacron sp.	1	0.3	3.6	16	5.3	9.1	0	0.0	0.0
Stenonema sp.	5	1.7	17.9	158	52.7	89.8	232	77.3	93.5
Tricorythodes sp.	0	0.0	0.0	2	0.7	1.1	0	0.0	0.0
Total	28	9.3	100.0	176	58.7	100.0	248	82.6	100.0
ODONATA									
Argia sp.	0	0.0		0	0.0	0.0	1	0.3	50.0
Enallagma sp.	0	0.0		1	0.3	100.0	0	0.0	0.0
Neurocordulia sp.	0	0.0		0	0.0	0.0	1	0.3	50.0
Total	0	0.0		1	0.3	100.0	2	0.6	100.0

Table 4-2. Continued.

PLECOPTERA									
Acroneuria sp.	1	0.3	25.0	0	0.0		4	1.3	6.9
Agnetina sp.	2	0.7	50.0	0	0.0		0	0.0	0.0
Paragnetina sp.	1	0.3	25.0	0	0.0		0	0.0	0.0
Taeniopteryx sp.	0	0.0	0.0	0	0.0		54	18.0	93.1
Total	4	1.3	100.0	0	0.0		58	19.3	100.0
COLEOPTERA									
Dineutus sp.	7	2.3	70.0	1	0.3	50.0	0	0.0	0.0
Optioservus sp.	2	0.7	20.0	0	0.0	0.0	1	0.3	100.0
Stenelmis sp.	1	0.3	10.0	1	0.3	50.0	0	0.0	0.0
Total	10	3.3	100.0	2	0.6	100.0	1	0.3	100.0
TRICHOPTERA									
Brachycentrus sp.	2	0.7	0.3	0	0.0	0.0	0	0.0	0.0
Ceratopsyche sp.	57	19.0	8.1	0	0.0	0.0	0	0.0	0.0
Cheumatopsyche sp.	270	90.0	38.3	90	30.0	81.8	674	224.7	74.3
Hydropsyche sp.	229	76.3	32.5	3	1.0	2.7	3	1.0	0.3
Hydroptila sp.	1	0.3	0.1	0	0.0	0.0	0	0.0	0.0
Macrostemum sp.	144	48.0	20.4	2	0.7	1.8	37	12.3	4.1
Mystacides sp.	1	0.3	0.1	0	0.0	0.0	0	0.0	0.0
Neureclipsis sp.	0	0.0	0.0	8	2.7	7.3	192	64.0	21.2
Oecetis sp.	1	0.3	0.1	4	1.3	3.6	1	0.3	0.1
Polycentropus sp.	0	0.0	0.0	3	1.0	2.7	0	0.0	0.0
Total	705	234.9	100.0	110	36.7	100.0	907	302.3	100.0
DIPTERA									
Ablabesmyia sp.	0	0.0	0.0	8	2.7	27.6	4	1.3	1.4
Cardiocladius sp.	14	4.7	1.9	0	0.0	0.0	0	0.0	0.0
Cricotopus sp.	10	3.3	1.4	0	0.0	0.0	30	10.0	10.3
Dicrotendipes sp.	0	0.0	0.0	0	0.0	0.0	12	4.0	4.1
Eukiefferiella sp.	0	0.0	0.0	0	0.0	0.0	6	2.0	2.1
Glyptotendipes sp.	7	2.3	1.0	0	0.0	0.0	0	0.0	0.0
Orthocladius sp.	0	0.0	0.0	0	0.0	0.0	24	8.0	8.2
Parametriocnemus sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	0.3
Polypedilum sp.	106	35.3	14.5	6	2.0	20.7	18	6.0	6.2
Rheotanytarsus sp.	161	53.7	22.1	3	1.0	10.3	189	63.0	64.9
Simulium sp.	416	138.7	57.0	0	0.0	0.0	0	0.0	0.0
Stilocladius sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	0.3
Tanytarsus sp.	0	0.0	0.0	0	0.0	0.0	6	2.0	2.1
Thienemanniella sp.	2	0.7	0.3	0	0.0	0.0	0	0.0	0.0
Thienemannimyia Gr.	2	0.7	0.3	0	0.0	0.0	0	0.0	0.0
Tvetenia sp.	12	4.0	1.6	12	4.0	41.4	0	0.0	0.0
Total	730	243.4	100.0	29	9.7	100.0	291	96.9	100.0
Grand Total (All Taxa)	**1481**	**493.7**	**100.0**	**410**	**136.7**	**100.0**	**1526**	**508.7**	**100.0**

Table 4-3. Macroinvertebrates Collected by Rock Basket Samplers at Station 227 During June, August, and October 2002.

	Month								
	June			August			October		
Taxon	Count	Mean	% of Total	Count	Mean	% of Total	Count	Mean	% of Total
NEMATODA	0	0.0		3	1.0	100.0	0	0.0	
Total	0	0.0		3	1.0	100.0	0	0.0	
PLATYHELMINTHES									
TURBELLARIA									
Dugesia tigrina	0	0.0		5	1.7	100.0	1	0.3	100.0
Total	0	0.0		5	1.7	100.0	1	0.3	100.0
ANNELIDA									
OLIGOCHAETA									
Nais communis	7	2.3	100.0	0	0.0		0	0.0	
Total	7	2.3	100.0	0	0.0		0	0.0	
MOLLUSCA									
GASTROPODA									
Amnicola sp.	1	0.3	50.0	0	0.0	0.0	0	0.0	0.0
Ferrissia sp.	1	0.3	50.0	19	6.3	63.3	47	15.7	58.8
Menetus dilatatus	0	0.0	0.0	0	0.0	0.0	2	0.7	2.5
Physa sp.	0	0.0	0.0	11	3.7	36.7	31	10.3	38.8
Total	2	0.6	100.0	30	10.0	100.0	80	26.7	100.0
CRUSTACEA									
BRACHIOPODA									
Cladocera	0	0.0		2	0.7	100.0	0	0.0	
Total	0	0.0		2	0.7	100.0	0	0.0	
CYCLOPOIDA									
Argulus sp.	0	0.0		1	0.3	100.0	0	0.0	
Total	0	0.0		1	0.3	100.0	0	0.0	
AMPHIPODA									
Hyalella azteca	8	2.7	100.0	18	6.0	100.0	16	5.3	100.0
Total	8	2.7	100.0	18	6.0	100.0	16	5.3	100.0
DECAPODA									
Orconectes sp.	0	0.0		1	0.3	100.0	1	0.3	100.0
Total	0	0.0		1	0.3	100.0	1	0.3	100.0
INSECTA									
EPHEMEROPTERA									
Baetis sp.	1	0.3	2.3	1	0.3	0.6	0	0.0	0.0
Caenis sp.	0	0.0	0.0	1	0.3	0.6	1	0.3	14.3
Isonychia sp.	1	0.3	2.3	1	0.3	0.6	0	0.0	0.0
Stenacron sp.	29	9.7	65.9	38	12.7	21.0	0	0.0	0.0
Stenonema sp.	13	4.3	29.5	139	46.3	76.8	6	2.0	85.7
Tricorythodes sp.	0	0.0	0.0	1	0.3	0.6	0	0.0	0.0
Total	44	14.6	100.0	181	60.2	100.0	7	2.3	100.0
ODONATA									
Argia sp.	0	0.0	0.0	11	3.7	64.7	0	0.0	0.0
Boyeria sp.	0	0.0	0.0	1	0.3	5.9	0	0.0	0.0
Enallagma sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	100.0
Neurocordulia sp.	3	1.0	100.0	5	1.7	29.4	0	0.0	0.0
Total	3	1.0	100.0	17	5.7	100.0	1	0.3	100.0
PLECOPTERA									
Acroneuria sp.	1	0.3	100.0	1	0.3	100.0	0	0.0	
Total	1	0.3	100.0	1	0.3	100.0	0	0.0	

Table 4-3. Continued.

COLEOPTERA									
Ancyronyx sp.	0	0.0	0.0	3	1.0	60.0	0	0.0	
Dineutus sp.	4	1.3	80.0	0	0.0	0.0	0	0.0	
Macronychus sp.	0	0.0	0.0	1	0.3	20.0	0	0.0	
Stenelmis sp.	1	0.3	20.0	1	0.3	20.0	0	0.0	
Total	5	1.6	100.0	5	1.6	100.0	0	0.0	
TRICHOPTERA									
Ceratopsyche sp.	1	0.3	1.0	0	0.0	0.0	0	0.0	0.0
Cernotina sp.	0	0.0	0.0	10	3.3	13.2	0	0.0	0.0
Cheumatopsyche sp.	64	21.3	62.1	0	0.0	0.0	1	0.3	5.6
Hydatophylax sp.	0	0.0	0.0	0	0.0	0.0	4	1.3	22.2
Hydropsyche sp.	1	0.3	1.0	0	0.0	0.0	0	0.0	0.0
Macrostemum carolina	1	0.3	1.0	0	0.0	0.0	0	0.0	0.0
Neureclipsis sp.	36	12.0	35.0	53	17.7	69.7	12	4.0	66.7
Oecetis sp.	0	0.0	0.0	4	1.3	5.3	0	0.0	0.0
Polycentropus sp.	0	0.0	0.0	9	3.0	11.8	0	0.0	0.0
Triaenodes sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	5.6
Total	103	34.2	100.0	76	25.3	100.0	18	5.9	100.0
DIPTERA									
Ablabesmyia sp.	2	0.7	1.9	5	1.7	17.2	0	0.0	0.0
Brillia sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	8.3
Cardiocladius sp.	12	4.0	11.7	0	0.0	0.0	0	0.0	0.0
Dicrotendipes sp.	4	1.3	3.9	5	1.7	17.2	3	1.0	25.0
Endochironomus sp.	1	0.3	1.0	0	0.0	0.0	0	0.0	0.0
Eukiefferiella sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	8.3
Glyptotendipes sp.	0	0.0	0.0	1	0.3	3.4	0	0.0	0.0
Nanocladius sp.	1	0.3	1.0	0	0.0	0.0	0	0.0	0.0
Orthocladius sp.	3	1.0	2.9	0	0.0	0.0	3	1.0	25.0
Polypedilum sp.	11	3.7	10.7	6	2.0	20.7	0	0.0	0.0
Rheotanytarsus sp.	69	23.0	67.0	9	3.0	31.0	3	1.0	25.0
Stictochironomus sp.	0	0.0	0.0	0	0.0	0.0	1	0.3	8.3
Tanytarsus sp.	0	0.0	0.0	3	1.0	10.3	0	0.0	0.0
Total	103	34.3	100.0	29	9.7	100.0	12	3.9	100.0
Grand Total (All Taxa)	**276**	**92.0**	**100.0**	**369**	**123.0**	**100.0**	**136**	**45.3**	**100.0**

5.0 FISH COLLECTIONS

General and anadromous fish electrofishing samples were collected at all of the Stations specified in the current NPDES permit (Figure 5-1). Larval fish were collected weekly from 8 May through 17 July 2002 in the vicinity of the ENVY intakes. Fish impinged on the circulating water traveling screens were collected weekly from 1 April through 7 May, 28 May to 17 June, 5 August through 1October, and finally on 28 and 30 October 2002. Station outages occurred from 10 May through 27 May, and again from 5 October to 25 October 2002, and the cooling water intake pumps were not used, therefore no impingement or larval fish samples were collected during these periods. Electrofishing specifically for anadromous fish was conducted twice a month in July through October 2002, at all of the Stations specified in the NPDES permit.

5.1 METHODS OF COLLECTION AND PROCESSING

Table 5-1 describes the station numbers, names and types of samples collected as specified in ENVY's current NPDES permit. The paragraphs below present the methods of fish collection and processing for electrofishing (both general and anadromous), impingement, and larval fish sampling programs.

5.1.1 Electrofishing - General Sampling

General electrofishing was conducted with a boat-mounted Coffelt Electronics Model VVP-15 electroshocker. Monthly sampling was conducted during May, June, September, and October 2002 in the evening beginning approximately 0.5 h after sunset at the following Stations: 102, 051, 052, 091, 416, 426, 724, 032, 614, and 217 (Figure 5-1). All fish collected in each sample were identified to species, weighed to the nearest gram (wet weight), and measured to the nearest millimeter (total length). NPDES permit conditions were met with respect to the general fisheries electrofishing program.

5.1.2 Electrofishing - Anadromous Fish

Anadromous fish electrofishing targeted juvenile American shad in collections that were conducted with the same boat-mounted Coffelt Electronics Model WP-15 electroshocker and sampling techniques used for general electrofishing (Section 5.1.1 above). These anadromous fish electrofishing samples were taken twice per month during July through October 2002 at Stations 624, 614, 613, 615, 031, and 725 (Figure 5-1). Non-target fish (non-clupeids) were not enumerated or identified during the anadromous fish electrofishing runs. Collected juvenile shad were weighed (to the nearest gram wet weight) and measured (mm total length). All anadromous fish electrofishing samples were successfully collected as specified in the current NPDES permit.

5.1.3 Impingement

Weekly and 24 h spring and fall impingement samples were collected on Monday and Tuesday of each week, 1 April through 7 May, 28 May to 17 June, 5 August through 1 October, and finally on 28 and 30 October 2002. Impingement sampling was not conducted during two outages, one for maintenance (10 May – 27 May), and one for refueling (5 October – 27 October), because the cooling water intake pumps were not operated. Weekly samples (i.e., Monday collections) consisted of back-washing the traveling screens into the collection bin. The debris was then examined for Atlantic salmon (spring) or American shad (fall). The screens were again back-washed approximately 24 hours later (i.e., Tuesday collections) and all fish were removed, identified to species, weighed (to the nearest gram wet weight), and measured (mm total length). The annual Atlantic salmon and American shad impingement limits of 365 Atlantic salmon and 974 shad were not exceeded during 2002. Current NPDES permit compliance was met with respect to impingement sampling.

5.1.4 Larval Fish

Larval fish sampling is required annually per the NPDES Permit starting in May and continuing weekly through July 17 of each year, when the ENVY plant is in an operational mode. When the plant is non-operational (i.e. during an outage), larval fish sampling is not required. During 2002, larval fish were collected once prior to the 10 May outage, and then sampling commenced one day after the outage ended (27 May), and continued weekly thereafter between 28 May and 17 July 2002 in the vicinity of the ENVY intake structure (Fig. 5-1).

A 50-cm diameter, 363-µm nitex nylon plankton net was towed behind the boat, at surface (approx. 0.3 m), mid (approx. 1.8 m), and near bottom (approx. 3.7 m) depths. A flume-calibrated, General Oceanics Inc. Model 2030R mechanical flow meter was mounted in the net mouth and used to estimate the volume of each tow.

During the 19 June 2002 collections, a problem was encountered with the bottom sample. The sampling equipment became entangled with the bottom resulting in a loss of equipment and no bottom sample was collected for that week. Sampling equipment was replaced and the following weeks sample was collected as scheduled. In the future, an effort will be made to have back-up sampling equipment on-board the sampling vessel during sampling to minimize the occurrence of missed samples.

The contents of the retrieved plankton nets were washed into a collection cup fastened to the distal end of the net. Larval fish samples were preserved in 5% formalin for laboratory sorting and identification. Ichthyoplankton was separated from debris using an 8x to 80x variable magnification dissecting microscope. Larval fish were identified to the lowest practical taxonomic level utilizing the following published larval keys: Fish (1930), Lippson and Moran (1974), Jones et al. (1978), and Auer (1982). All larval fish samples were collected in compliance with the current NPDES permit requirements, except as noted above.

5.2 SUMMARY

Twenty-seven species of fish were collected during 2002 (Table 5-2). The total number and species composition were similar to recent years (Aquatec 1993, 1995, and Normandeau Associates 1997-2002). All fish species collected were typical of the Connecticut River drainage. No federally listed threatened or endangered species were collected.

5.2.1 General Electrofishing and Impingement Fish Collections

During 2002, a total of 40 electrofishing collections were completed among the ten locations within the eight NPDES permit designated Stations (Fig. 5-1, Table 5-3). The total number of fish collected by electrofishing was 793 (Table 5-3). The total catch per unit effort (CPUE) for the 40-electrofishing collections was 118.4. The total electrofishing effort was 6.7 hours.

There were 1,562 fish collected in 2002 during impingement and general electrofishing, including electrofishing stations above and below Vernon Dam (Table 5-4). Numerically, the most abundant species were bluegill (30.3%), yellow perch (24.3%), and pumpkinseed (7.6%), White sucker (25.7%), bluegill (18.6%), largemouth bass (14.4%), yellow perch (9.2%), and smallmouth bass (9.2%) accounted for the majority of the biomass of collected fishes (Table 5-4).

Upstream of Vernon Dam, bluegill, yellow perch and pumpkinseed, accounted for 69.6% of the total number of all fish collected during 2002 (Table 5-5). Twelve Atlantic salmon and no American shad were collected upstream of Vernon Dam from the circulating water traveling screens (CWTS) at the Plant intake structure. Atlantic salmon and American shad numerically contributed 0.9% and 0.0%, respectively, to the total upstream catch. White sucker (26.4%), bluegill (20.6%), largemouth bass (17.5%), and yellow perch (11.3%) accounted for the majority of the biomass of the fish collected at the upstream Stations (Table 5-5).

Downstream of Vernon Dam, smallmouth bass, spottail shiner, American shad, bluegill, and rock bass accounted for 77.6% of the total number of fish caught during 2002 (Table 5-6). No Atlantic salmon and 21 American shad were collected downstream of Vernon Dam during the general electrofishing collections (i.e., not including anadromous species electrofishing collections conducted specifically for American shad). Smallmouth bass (37.1%), white sucker (22.9%), and bluegill (9.8%), contributed the greatest biomass to the downstream collections.

No American shad and 12 Atlantic salmon were observed in the impingement collections from the Entergy Nuclear Vermont Yankee traveling screens during 2002 (Table 5-7). All 12 of the Atlantic salmon were impinged during April 2002. The American shad and Atlantic salmon impingement limits of 974 shad and 365 salmon were not exceeded during 2002. The April and June sampling period yielded 91.0% of the total fish collected, 588 and 115 respectively. Yellow perch, bluegill, and sea lamprey were numerically the most abundant species in the impingement samples during the six months of sampling; however most fish were collected during April (Table 5-7).

5.2.2 Anadromous Fish Electrofishing

In fulfillment of the NPDES permit requirements for anadromous fish sampling, electrofishing samples were collected twice a month during July through October 2002 at Stations 624, 614, 613, 615, 031, and 725 (Figure 5-1). Results reported in this section include American shad collected and enumerated during the anadromous fish collections only and not those shad reported above in the general electrofishing section.

A total of 41 American shad were collected via electrofishing between July and October 2002 (Table 5-8). October yielded the highest catch of shad (18) compared to the other three months. Shad lengths recorded in October ranged from 90 – 112 mm total length and weight ranged from 4 - 10 g (Table 5-8). The twice-monthly collections during July, August, and September resulted in the collection of 0, 14, and 9 American shad, respectively. The American shad collected during August ranged in length from 67 - 87 mm. September shad collections produced a catch ranging in length from 71 – 103 mm. The CPUE in August was highest at the Station 031 (30.0) followed by Station 725 (12.0) (Table 5-8). The CPUE in September was highest at Station 725 (12.0) and the CPUE in October was also highest at Station 725 (27.0).

5.2.3 Ichthyoplankton

Twenty-six ichthyoplankton samples were collected near, but outside of the ENVY intakes between 8 May and 17 July 2002 (Table 5-9). A total of 1,378 ichthyoplankters were identified and enumerated (Table 5-10). Spottail shiners made up 89.7 % of the total ichthyoplankton collected. Common carp, fallfish, white sucker, white perch, centrarchidae, tessellated darter, and yellow perch made up the remaining 10.3% of ichthyoplankton collected (Table 5-10). Table 5-11 provides a breakdown of ichthyoplankton estimates presented as density (no./100 cubic meters). Most fish were collected at the 0.3 meters depth. With respect to time, spottail shiners were most abundant in July while all other species collected were more abundant in May and June 2002.

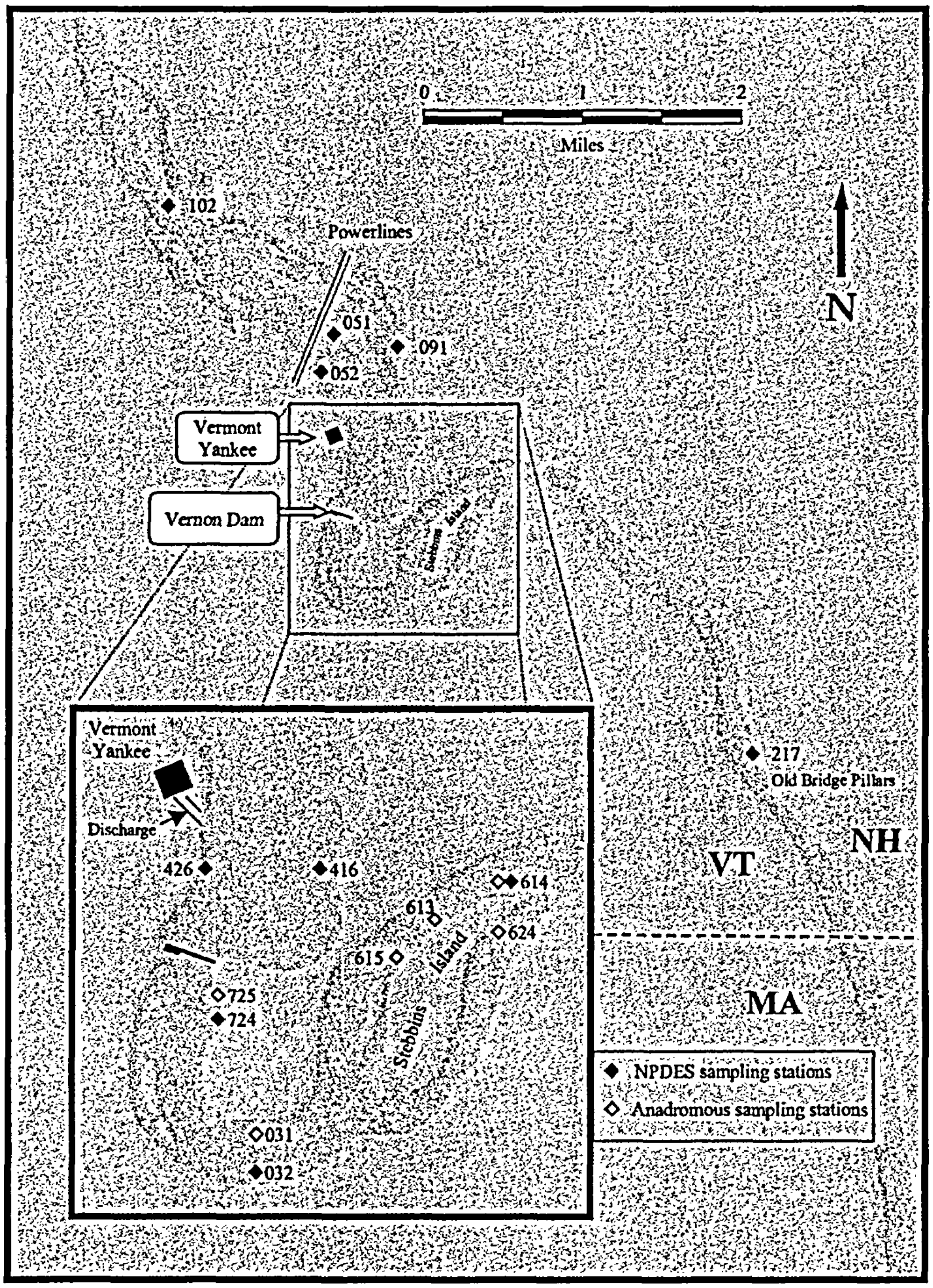

Figure 5-1. NPDES and Anadromous Fish Electrofishing Sampling Stations.

Table 5-1. Sampling Station Numbers, Names, and Descriptions of Sampling Conducted for the Vermont Yankee NPDES Program in the Connecticut River in the Vicinity of Vernon, Vermont.

Station Number	Station Name	Sample Type(s)
Downstream Stations		
217	Station 2 NH South	General electrofishing
227	Station 2 VT South	Macroinvertebrates, anadromous electrofishing
031	Station 3 NH	Macroinvertebrates, anadromous electrofishing
032	Station 3 VT	Water quality, general electrofishing
624	Stebbins Island VT Lower	Anadromous electrofishing
614	Stebbins Island NH Lower	Anadromous electrofishing
613	Stebbins Island NH Mid	Anadromous electrofishing
615	Stebbins Island NH Upper	Anadromous electrofishing
724	0.1 Mi. Below Vernon VT (Lower)	General electrofishing
725	0.1 Mi. Below Vernon VT (Upper)	Anadromous electrofishing
020	Vernon Dam Fish Ladder	Water quality, adult shad
Upstream Stations		
051	Station 5 NH	Zebra mussel, corbicula, general electrofishing
053	Station 5 Mid-River	Zebra mussel, corbicula
052	Station 5 VT	Zebra mussel, corbicula, general electrofishing
072	Station 7 VT	Water quality
091	NH Setback	General electrofishing
102	Rum Point	General electrofishing
300	VY Discharge	Water quality
416	Station 4 NH North	Zebra mussel, corbicula, general electrofishing
436	Station 4 Mid-River North	Zebra mussel, corbicula
426	Station 4 VT North	Zebra mussel, corbicula, general electrofishing
417	Station 4 NH South	General electrofishing
427	Station 4 VT South	General electrofishing
800	VY Intakes	Larval fish, impingement

Table 5-2. Checklist of Fishes (AFS 1991) Collected in the Connecticut River Study Area in the Vicinity of Vernon, Vermont During 2002.

Scientific Name	Common Name
CHORDATA	
AGNATHA	
PETROMYZONTIFORMES	
Petromyzontidae	
Petromyzon marinus	Sea lamprey
OSTEICHTHYES	
ANGUILLIFORMES	
Anquillidae	
Anguilla rostrata	American eel
CLUPEIFORMES	
Clupeidae	
Alosa sapidissima	American shad
CYPRINIFORMES	
Cyprinidae	
Cyprinidae	Unidentified carps and minnows
Hybognathus regalis	Silvery minnow
Notemigonus crysoleucas	Golden shiner
Notropis hudsonius	Spottail shiner
Semotilus corporalis	Fallfish
Catostomidae	
Catostomus commersoni	White sucker
SILURIFORMES	
Ictaluridae	
Ameiurus nebulosus	Brown bullhead
SALMONIFORMES	
Salmonidae	
Salmo salar	Atlantic salmon
Salmo trutta	Brown trout
Salvelinus fontinalis	Brook trout
Osmeridae	
Osmerus mordax	Rainbow smelt
Esocidae	
Esox lucius	Northern pike
Esox niger	Chain pickerel
CYPRINODONTIFORMES	
Cyprinodontidae	
Diaphanus fundulus	Banded killifish
PERCIFORMES	
Percichthyidae	
Morone americana	White perch
Centrarchidae	
Ambloplites rupestris	Rock bass
Lepomis gibbosus	Pumpkinseed
Lepomis macrochirus	Bluegill
Micropterus dolomieu	Smallmouth bass
Micropterus salmoides	Largemouth bass
Pomoxis nigromaculatus	Black crappie
Etheostoma olmstedi	Tesselated darter
Percidae	
Perca flavescens	Yellow perch
Stizostedion vitreum	Walleye

Table 5-3. Overall Catch Per Unit Effort (CPUE) for General Electrofishing Fish Collections in the Connecticut River in the Vicinity of Vernon, Vermont, During 2002.

Electrofishing Stations	Number of Collections	Hours	Fish	CPUE
Station 3 - Vermont (032)	4	0.667	59	88.5
Station 5 - New Hampshire (051)	4	0.667	117	175.5
Station 5 - Vermont (052)	4	0.667	69	103.5
New Hampshire Setback (091)	4	0.667	156	234.0
Rum Point (102)	4	0.700	86	122.9
Station 2 - New Hampshire (217)	4	0.667	44	66.0
Station 4 - New Hampshire (416)	4	0.667	82	123.0
Station 4 - Vermont (426)	4	0.667	68	102.0
Stebbin Island - New Hampshire Side (614)	4	0.667	52	78.0
0.1 Miles south of Vernon Dam (724)	4	0.667	60	90.0
Total	**40**	**6.700**	**793**	**118.4**

Table 5-4. Combined Total Number and Weight of Fishes Collected by General Electrofishing and Impingement in the Connecticut River Upstream and Downstream of Vernon Dam in 2002.

	Total (#)	Relative Number (%)	Total Weight (g)	Relative Weight (%)
Carps and Minnows	2	0.1	2106	2.1
Banded killifish	2	0.1	4	0.0
Sea lamprey	71	4.5	236	0.2
American eel	2	0.1	45	0.0
American shad	22	1.4	126	0.1
Atlantic salmon	13	0.8	476	0.4
Brook trout	1	0.1	1500	1.5
Rainbow smelt	1	0.1	15	0.0
Northern pike	1	0.1	850	0.8
Chain pickerel	5	0.3	989	1.0
Silvery minnow	6	0.4	25	0.0
Golden shiner	32	2.0	992	1.0
Spottail shiner	116	7.4	396	0.4
Fallfish	13	0.8	973	1.0
White sucker	34	2.2	25034	25.7
Brown bullhead	22	1.4	235	0.2
White perch	4	0.3	63	0.0
Rock bass	92	5.9	3106	3.1
Pumpkinseed	118	7.6	6755	6.9
Bluegill	473	30.3	18047	18.5
Smallmouth bass	86	5.5	8918	9.1
Largemouth bass	34	2.2	13991	14.3
Black crappie	14	0.9	484	0.5
Tesselated darter	9	0.6	20	0.0
Yellow perch	379	24.3	8988	9.2
Walleye	10	0.6	2902	2.9
TOTAL	**1562**	**100.0**	**97276**	**100.0**

Table 5-5. Number and Weight of Fishes Collected Upstream of Vernon Dam in 2002 in General Electrofishing and Impingement.

	Electrofishing		Impingement		Summary			
Fish Taxa	Number	Total Weight (g)	Number	Total Weight (g)	Total (#)	Relative Number (%)	Total (g)	Relative Weight (%)
Carps and Minnows	1	2100	1	6	2	0.1	2106	2.7
Sea lamprey	0	0	69	228	69	5.1	228	0.3
American shad	0	0	1	0	1	0.1	0	0.0
Atlantic salmon	0	0	13	476	13	1.0	476	0.6
Rainbow smelt	0	0	1	15	1	0.1	15	0.0
Northern pike	1	850	0	0	1	0.1	850	1.1
Chain pickerel	5	989	0	0	5	0.4	989	1.3
Silvery minnow	2	19	2	4	4	0.3	23	0.0
Golden shiner	29	886	2	104	31	2.3	990	1.3
Spottail shiner	17	39	59	272	76	5.6	311	0.4
White sucker	18	19611	10	1214	28	2.1	20825	26.4
Brown bullhead	0	0	22	235	22	1.6	235	0.3
White perch	3	58	1	5	4	0.3	63	0.1
Rock bass	5	56	74	1947	79	5.9	2003	2.5
Pumpkinseed	81	4764	27	1632	108	8.0	6396	8.1
Bluegill	197	7111	254	9142	451	33.5	16253	20.6
Smallmouth bass	6	1525	9	583	15	1.1	2108	2.7
Largemouth bass	31	13782	2	9	33	2.4	13791	17.5
Black crappie	4	107	7	371	11	0.8	478	0.6
Tesselated darter	1	1	8	19	9	0.7	20	0.0
Yellow perch	175	5675	203	3275	378	28.1	8950	11.3
Walleye	2	1450	4	370	6	0.4	1820	2.3
Total	578	59023	769	19907	1347	100.0	78930	100.0

Table 5-6. Numbers and Weights of Fishes Collected Downstream of Vernon Dam in 2002 in the General Electrofishing Program.

Fish Taxa	Total Number	Relative Number (%)	Total Weight (g)	Relative Weight (%)
Banded killifish	2	0.9	4	0.0
Sea lamprey	2	0.9	8	0.0
American eel	2	0.9	45	0.2
American shad	21	9.8	126	0.7
Brook trout	1	0.5	1500	8.2
Silvery minnow	2	0.9	2	0.0
Golden shiner	1	0.5	2	0.0
Spottail shiner	40	18.6	85	0.5
Fallfish	13	6.0	973	5.3
White sucker	6	2.8	4209	22.9
Rock bass	13	6.0	1103	6.0
Pumpkinseed	10	4.7	359	2.0
Bluegill	22	10.2	1794	9.8
Smallmouth bass	71	33.0	6810	37.1
Largemouth bass	1	0.5	200	1.1
Black crappie	3	1.4	6	0.0
Yellow perch	1	0.5	38	0.2
Walleye	4	1.9	1082	5.9
Total	**215**	**100.0**	**18346**	**100.0**

Table 5-7. Monthly Impingement of Fish on Entergy Nuclear Vermont Yankee's Circulating Water Traveling Screens in 2002.

Fish Taxa	April #	April Wt (g)	May #	May Wt (g)	June #	June Wt (g)	August #	August Wt (g)	September #	September Wt (g)	October #	October Wt (g)
Sea lamprey	69	228										
American shad							0	0	0	0	0	0
Atlantic salmon	12	466	0	0	0	0						
Brown trout	1	10										
Rainbow smelt	1	15										
Silvery minnow	1	2			1	2						
Golden shiner	2	104										
Spottail shiner	58	271			1	1						
White sucker	9	114			1	1100						
Brown bullhead	22	235										
White perch	1	5										
Rock bass	56	1391	3	8	11	333	3	213			1	2
Pumpkinseed	25	1490			2	142						
Bluegill	130	3039	6	12	78	159	27	4455	10	1419	3	58
Smallmouth bass	3	364			1	3	4	126	1	90		
Largemouth bass	1	6					1	3				
Black crappie	3	268					2	95			2	8
Tesselated darter	8	19										
Yellow perch	182	3159	2	9	19	107						
Walleye	4	370										
Carps and Minnows					1	6						
Total	**588**	**11556**	**11**	**29**	**115**	**1853**	**37**	**4892**	**11**	**1509**	**6**	**68**

Table 5-8. Summary of American Shad Caught During the 2002 Anadromous Electrofishing Program in the Connecticut River at Stebbins Island, Station 3, and 0.1 Miles Below Vernon Dam.

Month and Station	No. of Fish	Hours	CPUE	Minimum Length (mm)	Maximum Length (mm)	Minimum Weight (g)	Maximum Weight (g)
July							
Station 3 (031)	0	0.33	0	–	–	–	–
Stebbin Island (613,614,615,624)	0	1.33	0	–	–	–	–
0.1 Miles south of Vernon Dam (725)	0	0.33	0	–	–	–	–
August							
Station 3 (031)	10	0.33	30	67	87	4	7
Stebbin Island (613,614,615,624)	0	1.33	0	–	–	–	–
0.1 Miles south of Vernon Dam (725)	4	0.33	12	74	86	3	6
September							
Station 3 (031)	3	0.33	9	71	97	3	8
Stebbin Island (613,614,615,624)	2	1.33	1.5	95	103	7	9
0.1 Miles south of Vernon Dam (725)	4	0.33	12	80	100	4	7
October							
Station 3 (031)	5	0.33	15	91	98	4	6
Stebbin Island (613,614,615,624)	4	1.33	3	88	97	4	6
0.1 Miles south of Vernon Dam (725)	9	0.33	27	90	112	5	10

Table 5-9. Entergy Nuclear Vermont Yankee Ichthyoplankton Sampling Effort (Number of Tows) in 2002.

Depth (m)	May	June	July	Total
0.3	2	4	3	9
1.8	2	4	3	9
3.7	2	3	3	8
Totals	**6**	**11**	**9**	**26**

Table 5-10. Collection Dates and Total Number of Ichthyoplankton Collected Near the Entergy Nuclear Vermont Yankee Intakes in 2002.

Species	Earliest Capture	Latest Capture	Number	Percent
Common carp	2-Jul-02	10-Jul-02	2	0.1
Spottail shiner	4-Jun-02	17-Jul-02	1236	89.7
Fallfish	10-Jul-02	10-Jul-02	3	0.2
White sucker	28-May-02	19-Jun-02	2	0.1
White perch	28-May-02	2-Jul-02	75	5.4
Centrarchidae	2-Jul-02	17-Jul-02	27	2.0
Tesselated darter	13-Jun-02	13-Jun-02	4	0.3
Yellow perch	8-May-02	8-May-02	29	2.1
Total			**1378**	**100.0**

Table 5-11. Ichthyoplankton Density per 100 Cubic Meters at the Entergy Nuclear Vermont Yankee Intakes, by Depth, in 2002.

Collection Date	Fish Species	Mean Density at Depth (m) 0.3	1.8	3.7	Water Column Mean Density
8-May-02	Yellow perch	2.49	16.30	6.23	8.34
28-May-02	White perch	8.17	6.89	1.76	5.61
	White sucker	1.02	0.00	0.00	0.34
4-Jun-02	Spottail shiner	0.90	0.00	0.00	0.30
	White perch	3.61	2.47	8.71	4.93
13-Jun-02	Spottail shiner	7.05	2.00	0.00	3.02
	Tesselated darter	0.00	1.00	2.61	1.20
	White perch	1.01	3.99	2.61	2.54
19-Jun-02	Spottail shiner	1.06	0.00	0.00	0.35
	White sucker	1.06	0.00	0.00	0.35
27-Jun-02	Spottail shiner	6.57	13.06	3.80	7.81
	White perch	6.57	9.04	0.95	5.52
2-Jul-02	Centrarchidae	0.96	0.00	0.00	0.32
	Common carp	0.00	0.00	1.08	0.36
	Spottail shiner	81.62	10.42	16.18	36.07
	White perch	0.00	3.79	10.79	4.86
10-Jul-02	Centrarchidae	0.00	3.21	8.76	3.99
	Common carp	0.00	0.00	0.97	0.32
	Fallfish	2.79	0.00	0.00	0.93
	Spottail shiner	602.76	101.79	74.99	259.85
17-Jul-02	Centrarchidae	1.29	5.38	7.92	4.86
	Spottail shiner	116.22	138.72	50.49	101.81

6.0 2002 ZEBRA MUSSEL AND ASIATIC CLAM MONITORING

6.1 METHODS OF COLLECTION AND PROCESSING

Larval (veliger) sampling was conducted bi-weekly between 22 May and 21 October 2002. Collections were made at quarter points (NH and VT shores, and mid-river) at Entergy Nuclear Vermont Yankee stations 4 and 5 (Fig 6-1). Approximately 1,000 liters of river water was pumped through a 64-micron plankton net at each quarter point for each collection. Six samples were collected during each bi-weekly collection trip for a total of 60 pumped veliger samples in 2002. Samples were preserved in 70% ethanol for examination in the laboratory for the presence of the microscopic veligers.

Juvenile/adult (settling stage) zebra mussel sampling was conducted between 8 May and 21 October 2002 near the New Hampshire and Vermont shores at Vermont Yankee stations 4 and 5 (Fig 6-1). One settlement plate sampler was deployed at each station for a total of four samplers. Settlement plates were made of six, 6 in X 6 in plates of PVC strung onto a bolt with approximately 1.25 in between plates. The sampler was suspended in the water column at 2-3 m below the surface, depending on river depth at the sampling station. The plate sampler at each Station was examined approximately every two weeks for newly settled adult zebra mussels. One plate from each sampler was then randomly selected and cleaned into a number 64-micron sieve. The sample was then preserved in 70% ethanol for examination in the laboratory.

High river flows occurred for approximately five days in June 2002. Equipment loss was anticipated, so the zebra mussel plates were retrieved on 13 June and not deployed again until 19 June. Therefore, four samples were missed during the period 6 June through 19 June due to the high flow conditions.

One plate sampler deployed at Station 416 on 27 August 2002, could not be located two weeks later when retrieval was attempted. A new plate sampler was deployed at that location on the day after the plate sampler was determined to be lost and was checked approximately 2 weeks later for settlement. Therefore, one zebra mussel settling plate sample was not collected between 27 August and 13 September 2002.

A total of forty-two zebra mussel settling plate samplers were deployed during the period 8 May through 21 October 2002.

Asiatic clam (*Corbicula*) samples were collected with a 9-inch Ponar dredge in June, August, and October 2002 at Stations 051, 053, 052, 416, 436, and 426 (Figure 6-1). Dredge samples were collected at all six locations (near the New Hampshire shore, mid-stream, and near the Vermont shore) for a total of 18 dredges. All dredge samples were sieved through a standard USGS number 30-sieve in the field, prior to being preserved in 70% ethanol for later identification in the laboratory.

6.1.1 Laboratory Identification Procedures

Each zebra mussel veliger sample was emptied into a petri dish and examined in entirety with cross-polarized light on a dissecting microscope with 40x magnification. The use of cross polarized light allows zebra mussel veligers to be distinguished from other planktonic organisms that are also collected in the samples, as the larval shells stand out as bright spots against a dark background (Johnson 1996). In the laboratory, the 18 *Corbicula* Ponar dredge samples from each quarter point per location (NH, mid-stream, and VT), per station (Station 4 and 5) were examined in entirety under low magnification (2x).

6.2 SUMMARY

River water temperatures ranged from 9.8°C to 27.9°C, dissolved oxygen ranged from 7.2 to 12.2 mg/l, and pH ranged from 5.8 to 8.5 during veliger and settlement plate sampling in the vicinity of the Entergy Nuclear Vermont Yankee Plant (Stations 4 and 5).

There were no Asiatic clams or any life stages of zebra mussels found in any samples collected during the 2002 Vermont Yankee monitoring program.

In addition to the zebra mussel sample collections, zebra mussel information cards were distributed to local venders, such as sporting good stores, bait shops, and marinas, during 2002.

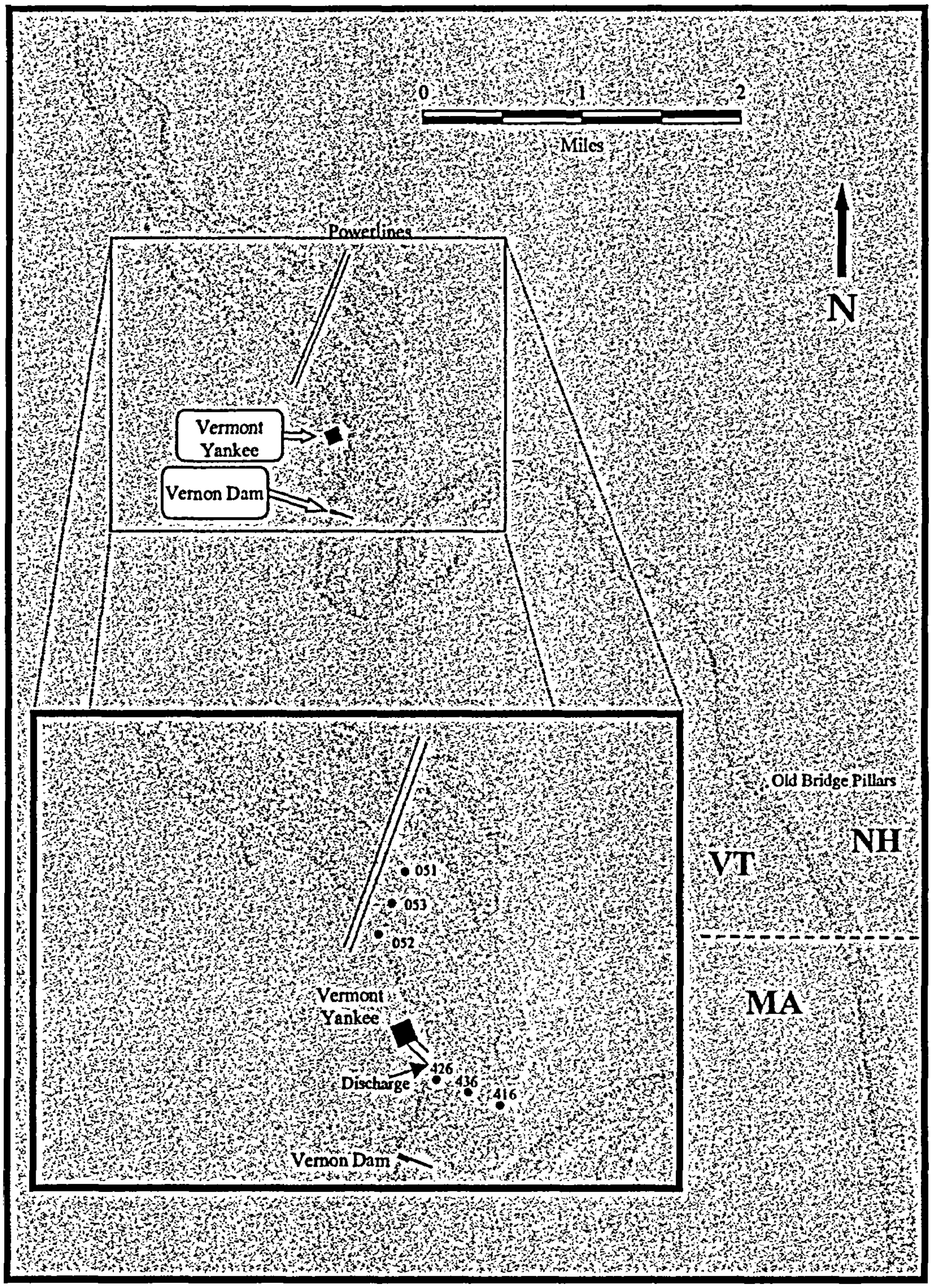

Figure 6-1. Zebra Mussel and Asiatic Clam Monitoring Stations (Zebra mussel veliger pump samples and Asiatic clam dredges occur at all Stations and zebra mussel plate sampling occurs at Stations 051, 052, 416, and 426).

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Docket No. 50-271
BVY 04-008

Attachment 4

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263

Extended Power Uprate – Supplement No. 5

Affidavit – General Electric

Docket No. 50-271
BVY 04-008

Attachment 5

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263

Extended Power Uprate – Supplement No. 5

Affidavit – Stone & Webster

COMMONWEALTH OF MASSACHUSETTS
COUNTY OF NORFOLK

AFFIDAVIT OF CHARLES E. CRONAN IN SUPPORT OF APPLICATION FOR WITHHOLDING PURSUANT TO 10 C.F.R. PART 2, SUBPART G, SECTION 2.790

Charles E. Cronan, being duly sworn, does hereby depose and state:

1. I hold the position of Vice President & Director of Engineering of Stone & Webster Power Division, and I am authorized to make the request for withholding from Public Record the information accompanying this affidavit.

2. The work underlying the information in question was performed under my authority, and I am responsible for the engineering divisions (s) performing the work.

3. The information that we request be withheld is the portion of the response (identified by [[ ]]) developed by Stone & Webster (S&W) in response to the NRC Request for Additional Information (RAI) No. IEPB-B-5 (VY RAI No. 127), transmitted by NRC letter dated December 18, 2003, in relation to the Vermont Yankee Power Uprate Application.

4. The S&W contribution to the response summarizes the power uprate assessment performed by S&W determining the adequacy of current normal operation plant shielding and radiation zoning following power uprate. The portions of the response identified by [[ ]] outlines evaluations and analytical methods utilized by S&W to asses the impact of an extended power uprate on radiation levels on-site and off-site from a boiling water reactor. These evaluation approaches have been developed by Stone & Webster over 20 years at substantial investment of resources and expertise and include many lessons learned from similar projects. The above constitutes a source of competitive advantage for our company in the competition and performance of such work in the industry. Public disclosure of the proprietary information is likely to cause substantial harm to Stone & Webster's competitive position and foreclose or reduce the availability of profit-making opportunities.

Further affiant sayeth not.

CE Cronan

Charles E. Cronan, Vice President
Stone & Webster Power Division

Signed and sworn before me this 26 7th day of January, 2004

Evelyn S. Clegg
Notary Public

EVELYN S. CLEGG
Notary Public
My Commission Expires May 8, 2009